BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS : RM01-12-000

RELECTRICITY MARKET DESIGN AND STRUCTURE :

- -x

Commission Room 2C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Monday, October 15, 2001

The above-entitled matter came on for workshop, pursuant to notice, at 10:05 a.m., Shelton Cannon, Moderator, presiding.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

APPEARANCES:

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Commissioner, Michigan Public Service Commission

PETER CRAMTON

Professor, University of Maryland

HONORABLE DAVID F. HADLEY

Commissioner, Indiana Utility Regulatory Commission

MARK D. KLEINGINNA

Corporate Energy Director, Ormet Corporation

JOHN MEYER

Vice President of Asset Commercialization, Reliant Energy

JOHN L. O'NEAL

President, Mirant Mid-Atlantic

ROY D. SHANKER, Ph.D.

-- continued --

APPEARANCES (CONTINUED):

HONORABLE MICHAEL CALLAHAN
Vice Chair, Mississippi Public Service Commission

EDWARD G. CAZALET
Chairman, Automated Power Exchange

STEVEN T. NAUMANN
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S. LORRAINE CROSS
Director, Federal Regulatory Affairs
Mirant Americas, Inc.

P R O C E E D I N G S

(10:05 a.m.)

COMMISSIONER WOOD: Good morning. Let's start today's proceedings with the Pledge of Allegiance to our flag.

(Pledge of Allegiance recited.)

COMMISSIONER WOOD: Good morning and welcome to our proceedings today. This is the first of five days of workshops on the very important topic of regional transmission organizations. I want to thank the Staff for their hard work in putting together a number, I believe ten, or nine or ten panels of folks who we think will add a lot of diversity and debate to these very important topics of what does an RTO do.

I should add for parties' interest that as we discussed earlier, we are dealing with in contested case proceedings issues relating to the size and to the governance of these organizations, but it's time to really focus in a lot of detail on what we want these organizations to do and how they should do that. And so today is the beginning of that effort to write the third book of a good trilogy so we can go ahead and get it to Hollywood and make it into a movie called Electric Competition Working for the Customer.

I don't have anything more to add today. I look forward to a good, diverse, interactive presentation. I encourage our panelists on this panel and on all other panels to be real open, listen to what other people say. I ask the Staff who are participating to actually engage in a conversation as opposed to throwing out positions and fighting tooth and nail for them. Let's talk about how we get the closure and find some consensus here. That's what the purpose of today and this week is all about is taking it to the level of consensus and building a collaborative relationship to make markets work for the customer.

So if my colleagues have anything to add?

COMMISSIONER BROWNELL: Let's go.

MR. CANNON: (Presiding) I'd like to welcome you all here today. My name is Shelton Cannon. I work in the Office of Markets, Tariffs and Rates. And my role today here is to be the M.C. so that hopefully we can make this dialogue very successful and workable.

I'm going to try to keep up the pace here, try to facilitate the discussion, make sure w e don't get stalled. I'd like to make sure we fully understand the underlying arguments and we can try to build sort of a baseline that we can move forward on. We're starting a little bit late today, but we hope to finish up this session about 12:30 or 1:00 with an hour for lunch and then begin the afternoon session at 2:00 to 5:00.

The purpose of RTO Week here is to try to have a week of intensive workshop discussions to try to provide some additional focus and guidance for RTOs moving forward. The goal was articulated by the Commission in it September 26 meeting, and that goal is a seamless national power marketplace. So the question now is how do we get there. We need to sort of develop a To Do list and we need your help to do that. We need to figure out what the industry needs to do and what we as federal regulators need to do and equally importantly, what state regulators need to do.

We have loaded up this workshop with a lot of state participation because we think their participation is absolutely critical to making this a success. There are state representatives on every workshop panel and then a special Thursday morning session devoted totally to state issues.

I would encourage any state commissioners who want to participate in that Thursday morning session. We can certainly broaden it even beyond the participation that we've already established.

The structure, as the Chairman mentioned, is ten workshops loosely organized around the whole concept of electric market design and structure. Now that's a huge topic and we recognize it's a lot of ground to cover. But what we did is we tried to go out and find some, to use in

ERCOT terms, some RSGs, which is a nonsexist way of saying real smart guys and gals to sit down and just engage in a very conversational debate around these various issues and try to look for solutions, not rehash a lot of old ground.

There's no PowerPoint, no canned presentations. Before we start each session, I want to have one member of the Staff kind of frame the issues that we have developed and brainstormed about for that particular panel. Feel free to go beyond those issues if we miss something. But I will also feel free to sort of rein things in if I think we're getting too far off the topic.

All of our RSGs are more than welcome to make an opening statement, but we'd like to keep that short. It's certainly not required. Again, we're much more interested in trying to get to the actual debate. We want this to be a conversation. There are a lot of overlapping issues. We've tried to order them and sequence them in a way that we think makes sense, thanks to Dick O'Neill and to Kevin Kelly and Scott Miller for at least taking the first crack at that.

Today we're going to be focusing on RTO markets and market design. Tomorrow we're going to get into transmission constraints, both short-term and sort of some of the solutions to that in terms of congestion management, as well as long term and what we do in terms of planning and expansion decisions.

Wednesday we're going to be talking about standardizing RTO tariffs and cost recovery issues. Thursday morning, as I mentioned, is devoted to state commissions and hopefully we'll be able to work through a lot of the jurisdictional issues that may be there. And in the afternoon of Thursday, we'll be talking about standardizing market and business practices. It sort of builds on our earlier seams conference from a few weeks ago.

And then Friday, once we've figured out all the answers to all those questions which I'm sure we will have done by Thursday, we're going to be getting into market monitoring and how we mitigate market power.

Now again I realize that's a very ambitious agenda for one week. There's a lot of linkages between these topics, so please don't feel shy if we've left anything out or if you see additional linkages that maybe we have missed. Because we need to understand them in a way that allows us to sort of sequence our efforts going forward.

Keep in mind the three basic themes for this Commission have been infrastructure, getting the rules right and market oversight, effective market oversight. Each of those three themes I think are going to play into all of the panels that we're going to have. The focus of these workshops is on the functions rather than the characteristics in Order 2000. So we need your help figuring out, you know, where do we standardize, where do we not standardize, what do we do now, what do we do later, and what are the best models out there.

With that, I'd like to turn it over for an opening statement from the Honorable David Svanda from Michigan.

MR. SVANDA: Thank you very much and good morning, Mr. Chairman, Commissioners, friends. Thank you very much to each of you and all of you for the opportunity to present comments on regional transmission organizations. I am Dave Svanda of the Michigan Public Service Commission. I'm also the Second Vice President of the National Association of Regulatory Utility Commissioners, affectionately known as NARUC.

My comments today, however, reflect the thoughts of a group of my colleagues representing regulatory commissions in Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio and Wisconsin. And I have with me today two colleagues representing states that I've just named on my left, your right. As you all know, David Hadley, Commissioner from Indiana, and on my right, your left, Commissioner Gary Gillis from Kentucky. And we're here to provide some embodiment to the ideas that we'll be presenting to you.

We each share this Commission's belief expressed by Chairman Wood that we must have an effective federal-state partnership to move forward on RTO formation and that we are prepared to begin that partnership today. Midwest state regulators have been engaged in RTO development for some time.

On June 4th, 1998, June 4th, '98 in Indianapolis, we began to formally warn the FERC about the consequences of their inaction with respect to the formation of ISOs. In presentations to the FERC in St. Louis on February 11th of '99 several of my Midwest colleagues urged the FERC to use its authority to provide the leadership for multi-state RTO formation. In my testimony I cautioned, if we proceed on a voluntary basis, it is very likely that RTO formation will proceed at an impossibly slow pace which will interminably delay the competitive electricity market that we, Michigan, seek.

Former Ohio Commission Chairman Craig Glaser raised eyebrows when he implored the FERC to just do something. He was, however, expressing the collective frustration that Midwest states were feeling back then. In fact, a very young but wise state commissioner colleague from Texas was at that same St. Louis forum making some very similar points. You recall that cold day in February, don't you, Mr. Chairman?

And now here we are. We're here in October of 2001 still embroiled in many of the same issues. Midwest regulators have been working with transmission owning utilities, merchant plant developers, marketers and other stakeholders as they grapple with the myriad of issues surrounding the formation of the Midwest Independent System Operator or MISO. You say MISO, we say MISO. And the Alliance Regional Transmission Organization or ARTO. But the progress has been excruciatingly slow and difficult.

Several states in the Midwest, including Michigan, are subdivided by arbitrary MISO and ARTO boundaries. We have seen transmission owners jump from MISO to ARTO and back again as conditions change and attitudes shift. State regulators and other stakeholders labored long and hard with both MISO and ARTO members to achieve a settlement agreement intended to facilitate a seamless market in the Midwest region. This MISO/ARTO settlement includes a single transmission rate methodology for the MISO/ARTO Super Region and an Interregional Coordination Agreement which provides a pass to achieve the coordinated operations and compatibility between the two entities on several key functions.

Covered functions include such things as ATC determination and coordination, security coordination, congestion management and regional planning. Thanks to critical input by the FERC staff and fast action by the FERC, the settlement was approved and the process moved ahead. We have Commissioners Massey and Breathitt to thank for that.

However, the MISO and the ARTO have not yet resolved critical issues, and serious problems remain in achieving the seamless market envisioned under the MISO/ARTO Coordination Agreement. These problems warrant the significant bolstering of our mutual efforts to precipitate a viable, fully functioning electricity market in the Midwest. Together, we can do and should do much, much more.

This week you'll hear many views on important RTO issues, including market monitoring, design and structure and so forth. I believe that you will find state regulators have very unique perspectives and great additions to make to your conversation. We subscribe to the major goals in your September 26, 2001 meeting and understand that these goals are not negotiable. We would like, however, to help with the details.

A partnership between the Commission and the states would greatly improve the resolution process for all of the RTO stakeholders in the region. The Midwest states want to help you to prove that a regional FERC partnership can work and have a very beneficial impact on the economic, reliability and security considerations of the region. In short, we would like to help create a model partnership and demonstrate the benefits of cooperative federalism based on trust among and between state, regional and national regulatory interests.

The Midwest region, roughly 18 states, is encompassed by the MISO and ARTO boundaries, is a diverse and economic powerhouse. With a combined population of over 97 million, the electric grid powers a $3 trillion gross state product economy that ranges from heavy manufacturing to agriculture with substantial high tech in between.

The Midwest electric system is also huge, with over 100,000 miles of transmission and 183,000 megawatts of installed capacity. In contrast, California's population is 33 million and they have a gross state product of $1.1 trillion, or about one-third the size of the region that we're discussing. I draw this comparison just to emphasize that the Midwest region is significant enough to warrant your immediate attention.

For the most part, the Midwest states have been working cooperatively on RTO issues through the MISO stakeholder process and our own ad hoc working groups. However, the ARTO stakeholder process has not yet been established, so the Midwest states have had no effective input on the critical organizational and functional issues which are being decided by the ARTO member transmission owners.

Voluntary cooperation between the Midwest states is evident in the joint filings in a number of Commission dockets related to the MISO and ARTO. What is missing is a coordinated, formalized process where this regional cooperation rapidly translates into a Midwest-FERC partnership and gets results.

We believe that the Federal Power Act gives the Commission the authority to formalize a real Midwest-FERC partnership. We point you to Section 209(a) of the Federal Power Act which provides for this, and my written comments do include that citation, but I will not read it here. Under this section, there is no requirement that FERC have any membership on this Board or any continuing role in its proceedings.

However, I strongly suggest that it would be very appropriate for the FERC to interpret the statute in this instance to include its own membership or leadership of this Board. It's envisioned that any party could petition the FERC to refer a matter to the Board review.

Skipping on, we do not propose this partnership to cause delay. We're all getting much too old for that. We consider the RTO implementation date of December 15th, 2001 a deadline, not a suggestion. RTOs must be up and running as soon as possible. We envision this partnership as a means to expedite the resolution of important going forward regional issues.

There is much to be solved and resolved to ensure that the MISO and ARTO settle outstanding issues and achieve the seamless market that we all seek in the Midwest. The Midwest states are eager to proceed with the Board if that's the process that you so choose. We'd also be very amenable to any other partnership arrangement that might better suit your interpretation or needs.

FERC Staff mediation and/or arbitration is welcome, along with the assistance of attorneys, economists, market and technical experts and any others that might help us to achieve our mutual goals. Appointment of an interim FERC Midwest state taskforce to address near-term issues would also be a possibility. The important thing is that we move forward quickly toward our common goals in a cooperative, coordinated fashion. We will pull out all the stops and commit all the necessary resources and energy to get this model created and functioning and solving problems if you will make the same commitment.

In this era of uncertainty and change, we cannot expect a solution that will work forever. It's imperative that we continue to work together and nurture a highly reliable and vibrantly competitive regional market. We in the Midwest would like to be in the vanguard of establishing a partnership with our federal colleagues because we view such cooperation as critical to the progress we all desire. A Midwest-FERC partnership will help us achieve these important goals. We ask for your careful consideration of this request and a quick response so that we all know how to allocate our time and resources.

As partners, we also promise that we'll work diligently to bring in additional MISO and ARTO states as quickly as possible.

Thank you for the opportunity. We certainly would be happy to answer questions. I might add a point that I failed to make at the outset. We are here as a bipartisan group appointed with different letters attached to our names. We're also here from states representing the full spectrum of interest and concern about the states moving to retail open access. And so we do represent truly the entire spectrum in that regard.

Thank you very much.

CHAIRMAN WOOD: Dave, and Dave and Gary, thank you all for coming today. It helps I think frame what most perceive as being a core issue for all of us is how to recognize that the laws that's written today kind of places some things in our court and some things in your court, but I think we all know that whoever's court they're in, they all have to be addressed.

And I personally like your suggestion of 209, a joint board. From the telephone side, I found that to be maybe not the most efficient but certainly the most effective way to ultimately get results on the telephone agenda when we were over there. If there are better ones and other ones, I'm sure we can figure that out in the next, you know, short period of time. But I do look forward to giving you all a specific quick response from all of us as soon as we have the chance to kind of kick it around among the four of us and talk to you all about how that might work. But it clearly is a threshold question, and I thank you for your leadership in taking what is the heartland of the country and making that a role model for how we and you can work together to deliver benefits to the customer.

COMMISSIONER MASSEY: Commissioner Svanda, thank you. Commissioners, thank you for coming today. Dave and I have been in a conversation about RTO policy for a number of years now, and I've always been heartened by the filings from the Midwestern states because the philosophy of your filings in case after case has been we want good, robust wholesale markets, regardless of whether our state is moving to retail competition or not, we think this is in the national interest. And that is a strong theme in all of the pleadings that you have filed here. And I want you to know how much I appreciate your input and your interest in resolving these critical issues.

COMMISSIONER WOOD: Thank you all very much.

MR. CANNON: Yes. Thank you. We'll do a little chair shuffling here. Our first panel, let me give you their names and then I'll have Dave Mead from our staff sort of frame the issues for this panel. With us this morning we've got Professor Peter Cramton from the University of Maryland. We've got from our first panel or I guess our Panel 1A, the Honorable David F. Hadley, the Commissioner from Indiana Utility Commission. We've got Mark Kleinginna, who is the Corporate Energy Director for Ormet Corporation. We've got John Meyer, Vice President of Asset Commercialization with Reliant Energy. We've got John L. O'Neal, the President of Mirant Mid-Atlantic, and last but certainly not least, Dr. Roy J. Shanker.

Dave?

MR. MEAD: Good morning. My name is David Mead. I'm with the Office of Markets, Tariffs and Rates. This morning the panel will discuss issues associated with RTO markets and design with respect to markets, especially energy and ancillary service markets, that should be required to be operated by RTOs.

This afternoon's panel will address similar issues regarding markets that RTOs should have the option of operating. And tomorrow' panel will address transmission markets and how to manage congestion.

This morning the first issue is to explore what markets should be required to be operated by RTOs and which should be optional for the RTO and which should be left to entrepreneurs to create. For the required markets, which should have a standard market design for all RTOs, and where should the Commission allow region-specific choice among market design? Where a standard market design should be required, which is the best design to implement.

With regard to energy markets, what is the best way for an RTO to procure imbalance energy, and what is the best way to design real time markets for energy? Hopefully, comments on this issue will address both the supply side and the demand side of the market.

Finally, what about procuring ancillary services? What is the best way for the RTO to procure them? Does the answer depend on whether sellers have market power in that particular market? And what is the best way to recover the costs of ancillary services?

In brief, these are the major topics that we would like to cover this morning, and we're looking forward to hearing your views. Let me turn the microphone back over to the M.C.

MR. CANNON: With that, does anybody have a short opening statement they would like to make? We'll start down at the other end. Since I announced you last, we'll let you go first. Dr. Shanker?

DR. SHANKER: Thank you. My name's Roy Shanker. I'm an independent consultant. I've been working for the last six or seven years in the ISO development process in both New York in PJM, a bit in New England also for some of the utilities in the Southeast. I work for a wide range of clients, principally generators and marketers, but I'm here today as myself, and these are my own comments.

I wanted to hit four major points that I think hopefully put a little bit of structure around the issues that David brought out and that we've seen on the comments that were sent to us. The first has to do with sort of the main engine, the main element of market design, and that's the real time market. And what we want to talk about is how do we solve that problem and what are the requirements we have to address? And there's two principal requirements.

The first is that we have to have somebody operating the system. There's got to be a system coordinator, a system operator, somebody has to manage what's going on. You can't have people indiscriminately turning on and off generation. Someone has to see the system simultaneously, understand the operations of the unit, secure operations, recognize security constraints on the system and coordinate them.

The second is we're here sort of to discuss the market. And in the general sense of a market, we have to have a mechanism of communicating between market participants, generators and loads, and that system operator. The Commission has made it clear in Order 2000 that the mechanism for that communications is supposed to lead to an efficient market. Economic efficiency is the underlying goal in the objectives that you've put forward.

Now the intersection of those two requirements, someone that actually operates the system and coordinates it, and the mechanism of communicating economically, efficiently, yield one result. It's a result we've seen in the Northeast, in PJM in New York and the standard market design in New England, and that's the proverbial bid-based, security-constrained economic dispatch and the resulting locational marginal prices or nodal pricing. That's the solution. It encapsulates all the information that revolves around what you've talked about and want to address today.

It gives us marginal costs for generation, it gives us marginal costs for load. It gives us the opportunity costs or marginal costs for transmission. It sets up the system for property rights for transmission. It manages congestion. It gives virtually all the instruments that we're going to talk about today are subsumed within that solution.

Second thing is ancillary services. In theory we're done when we have that basic market design put in place in an energy-only market. We don't even need reserves. We don't need operating reserves, anything else, but we'd have a very volatile market. Everybody would not tolerate this. I'm not proposing it. But it's the theoretical paradigm that we're working against. And we'd see all the right pricings. For a variety of reasons, we don't let that happen. We put in operating reserves. We commit units a day ahead. We ask for regulation services. We may even have long-term adequacy requirements like the ICAP markets. And in collective form, those are the ancillary services. They are essentially adjustments to that pure energy market that make it acceptable for us in terms of both price volatility and operating reliability.

So the second key observation is, what we're talking about as ancillary services are a coordinated adjustment to that spot energy market. And the other observation about that is that they all have a uniform impact, which is they tend to turn on more generation and suppress prices. And we like that, because it holds to a stable operating environment. But what it means is that when we design the ancillary services markets, we have to coordinate all the pieces so that they complement what we did by adjusting the real time energy market and yield compensation that makes up for what I always refer to as the missing money by turning on the extra generation.

Third item. This isn't new. While there's a lot of controversy about this, the bottom line is what I've described is what almost every utility that I am aware of does internally and has done for a long time. Instead of bids, they have their internal costs. Instead of the prices that are transparent to the market, they historically haven't had to show them to anybody. They're all there and they're embedded in their current operating systems. I'm not aware of an energy management system by any utility today that doesn't yield this exact same information.

And the final item, not only is it old in the sense that we can do this, it's doable at a regional scale. I recently had some studies conducted for myself in the context of the Northeast mediation that looked at the tools needed to do this. It looked at the real time dispatch tools. It looked at the state estimators, the AC security analyses, all the tools for the real time market, and the conclusion was we can do it, we can do it quickly. The software is there now. It's out there to be implemented, and it can solve in a timeframe consistent with the real time markets, on the order of two or three minutes.

And that's it. Only six seconds over.

MR. CANNON: Thanks. Mr. O'Neal?

MR. O'NEAL: Good morning, Mr. Chairman and members of the Commission. My name is John O'Neal. I am President of Mirant Corporation's Mid-Atlantic business unit and live here in the Washington, D.C. area.

Mirant is a global energy company with over 21,000 megawatts of generation in Europe, Asia and North America. By far, our largest base of operations is here in North America where we own over 15,000 megawatts of generation. In addition to being a generation over, we're also a top five marketer of both electricity and natural gas.

Here in the Mid-Atlantic, we own 5,000 megawatts at plants in Maryland and Virginia, and we're proud that our electricity serves the nation's capital.

The perspective I bring to the panel today is that of a former electricity trader. Prior to my current assignment, I traded electricity and managed the dispatch of our generation assets into the Western markets. Let me begin, Mr. Chairman and Commissioners, by saying that Mirant strongly supports the creation of regional transmission organizations. We believe that RTOs will increase reliability and decrease cost to consumers in the long run.

Let me make four quick points to support your efforts here today. One, the Commission should act swiftly and prudently to establish RTOs. We believe there are substantial savings to be gained and that there are proven market mechanisms that exist that will allow for the quick formation of RTOs.

Two, the Commission needs to put strong, independent governance mechanisms into place. Our experience across the country points out time and time again the importance of strong, independent boards who make sure that market rules are fair and workable for all market participants.

Three, the Commission needs to provide certainty. It's an obvious point that businesses need a measure of certainty in order to make prudent investment decisions. We believe the formation of RTOs will provide clarity to our industry and will hasten the development of much needed transmission and generation infrastructure.

And four, Mirant fundamentally believes that restructured markets will ultimately lower prices to consumers. RTOs are a necessary step to creating competitive retial markets. Large regional energy markets will increase the number of suppliers willing to compete for retail customers. In fact, Mirant recently commissioned a study which modeled the Northeast as if one RTO reality. Our study showed potential savings to customers of over $400 million.

Thank you, Mr. Chairman and members of the

Commission for the opportunity to be here today. I look forward to participating in your panel.

MR. CANNON: Mr. Meyer?

MR. MEYER: I appreciate the opportunity to be here, Chairman Wood and fellow Commissioners. I'd like to say a few words about first of all an introduction of myself and then some of my thoughts on the market structure.

First of all, I have a B.S. in electrical engineering and a master of science also. I've spent 31 years in the industry, 14 operating energy control centers and power plants, 10 in T&D design and operation, seven years in the unregulated market where probably I've gained most of my experience both in Argentina and the U.S. In two of those years I led stakeholder groups in the state of Texas in designing both the wholesale market and the ISO around it, and finally the market structure that we have today.

Some of the important facets I'd like to cover in those areas. First of all, one of the things I think that was the most important is that FERC needs to give guidance, a little more guidance on how RTOs are to be formed. For instance, in Texas, ERCOT, there are several key things that we knew going in as stakeholders that wasn't needed to be designed. First of all, we knew everybody was under the RTO tariff. That was by state law and the Commission direction.

We knew what the cost was going on. There wasn't a lot of flexibility I guess. It was standardized pretty much. We knew what the governance was going to be, and it was totally independent. We knew the exact functions that were required of the RTO, at least on a high level, and we knew that stakeholders were meant to be totally involved in the market structure design.

I think those key things are very important in giving the stakeholders the basis to know where to react. As far as other things that need to be done, I think there's some standards required in market design, such as the required market products that we need to worry about, the transmission congestion for compatibility, how do we handle scheduling between RTOs, and how do we settle transmission costs between the RTOs, which I think right now is kind of just guess which is the best way.

As far as the big topic today I guess on some of the market designs, there's numerous large decisions to be made, such as are you going to have a bilateral market versus a Power Pool approach? What is your congestion management system? We've already heard LMP and we'll hear I'm sure before it's over the flowgate or the zonal models. What type scheduling requirements are you going to impose? Does everybody schedule? Do part of the people schedule? Do we have unbalance, balance, et cetera?

The RTO does have some necessary markets to deal with, but it's very important that no player can influence those markets, including transmission providers. The markets the RTO needs to be involved with, at least on a day ahead, are at least on a day ahead, or at least spinning reserve, non-spinning reserve and regulation. Also I'm a very strong believer that people scheduling should be able to self-arrange their ancillary services with RTO deployment.

The RTO also I believe has to be the sole person acquiring imbalance energy, both in real time and what I'll call spot market, which may be hour ahead, could even be longer depending on the exact market design. But typically, I'd say hour ahead back toward real time.

Perhaps one of the more important things, and I think I heard Dr. Shanker mention it earlier, was that sellers and buyers should see exactly the same market price when they're settled. And I think is key whether you're in a zonal model or whether you're in an LMP model, whatever. If you have load and generation with different bids, load bidding, load will never see the right price signal, it will discourage load to bid, and that I think is one of the major problems. I didn't mention that, but I think that load participation in all the markets run by the RTO is essential.

Finally, I guess I'd like to see a stakeholder process defined by FERC which would ensure that they are involved in the market structure and approve it. And to me, there's so many sectors, probably in the order of five, though we could argue that for a long time. Each sector should get equal voting, and I think two-thirds of the sectors would have to take action.

This particular design is important because it allows everybody to have an equal footing in the process. And when you get through with it, you have an RTO filing that may be made by transmission providers or owners, but it will have support of the majority of the participants in the market, which I think would alleviate a lot of your concerns. And certainly that's what's happened twice in Texas when we've gone down this approach.

With that, I think I've covered the major topics and will reserve the other comments for later. Thank you.

MR. CANNON: Commissioner Hadley?

MR. HADLEY: Thank you very much. Appreciate, Mr. Chairman and Commissioners and Staff at the table for the hard work that you've done and for calling this session together.

As a commissioner, I am not the technical policy analyst for our staff nor profess to know the depth of knowledge that the people beside me in these panels do. So

I'd like to step back and think of the bigger issues on market design that permeate a lot of the thoughts that the state commissions collectively in the Midwest have been expressing.

From the very inception of the RTO concept, I would share with Commissioner Svanda that numerous Midwest states have been actively engaged through individual as well as collective filings in expressing our support in working with FERC to achieve a single, reliable and efficient RTO for the Midwest. As Commissioner Svanda stated, across different political landscapes, across states that have entered into retail competition and those that have chosen not to, among those with different letters behind our names, we've been remarkably consistent in our support for the development of RTO and principles embodied in Order 2000.

And just as our nation is now attempting to get back to normal, now is a very appropriate time for you to be holding this session, a time for this Commission to act, a time to develop consistency, predictability and reliability, a key word that we are very strong in feeling about, that are all necessary components of RTO market design and cannot be forgotten as we think about the more technical aspects.

Several basic tenets have been articulated by the Commission and supported by the Midwest state commissions. The very first and foremost in Order 2000 was the requirement of independence. This Commission reaffirmed this principle in its July 12th Alliance order when the Commission made clear that it remains committed to assuring the independence of RTOs from control of market participants.

The Midwest states have consistently addressed what we consider to be a potential fatal flaw in market designs. And specifically, that fatal flaw is the still unresolved fundamental seams issues among the RTOs in the Midwest. To that end, the Midwest states made a filing requesting mediation as recently as August of this year. We said such mediation process could be utilized as a forum for the parties to address continued and expanded RTO development in the Midwest, which could include the development of a single RTO that would encompass the entire Midwest natural market.

This was in keeping with our own March filing in response to the settlement agreement between the Midwest ISO and the Alliance transmission owners in which I would quote that the Midwest commission stated that our goal was to achieve seamless wholesale power markets which would cover the entire natural Midwest market. In that same filing, we noted that the state commission's decision not to contest the settlement agreement should not be construed as wholehearted support of the agreement.

With respect to a seamless Midwest market, we said, and again I quote, "there remains a significant distance between aspiration and achievement". Just as those words were true in our filing in March, unfortunately today, seven months later, they are still painfully true.

The existence of two organizations, we further stated, rather than one will impose some cost implication. Far more critical than cost redundancy is the expenditure of time and dollars on communication equipment that may not be fully compatible, software that may not be consistent, and even hardware that may cause compatibility issues.

The state commissions take little comfort in the promise that over the course of the next year or two it will become clear to the Commission that the Alliance RTO and the Midwest ISO will have achieved results for a seamless market, and that's from the Alliance update report on the ERCOT.

Based on the state commission's experience over the last several years, these vague assurances give us little comfort. To allow such market design without decisive intervention by this Commission is not in the public interest in our opinion. To ensure the integrity of market design, safeguards such as effective market monitoring must be in place. We feel that market monitoring is an important part of this discussion. We look forward to that part of the discussion this week.

We think that a vital part of that market monitoring has to be access to information. Data collection needs to be standardized, accessible by the market monitor as well as state commissions, this Commission and other agencies as being necessary. And we believe the market monitor must be allowed to report to those agencies necessary and not be held solely responsible to the RTO itself. To ensure market designs that are achieved with customer surety, investors in the markets' surety, and the consistency of thought across all of these issues, market design is very important and a great way to begin this. We thank you for holding this session and look forward to the rest of this.

MR. CANNON: Thank you, Commissioner Hadley. Mr. Kleinginna?

MR. KLEINGINNA: Good morning. Thank you for allowing Ormet to participate on this panel. Ormet's Hannibal facility consumes 4,500 gigawatt hours annually. That is as much electricity as all the loads in the entire city of Pittsburgh. Our peak load is about 535 megawatts. Our wholesale electric procurement strategy has met with both long-term and short-term difficulties. These difficulties stem from one source: That is uncertainty. Uncertainty with respect to the transmission grid.

There are short-term information problems which cut schedules in an arbitrary fashion as a result of TLRs which occur in the wee hours of the morning on shoulder months. There are long-term rate design and product design uncertainties which make any risk management strategy a crapshoot.

FERC must act to ensure that wholesale transmission barriers do not inhibit willing buyers and sellers from coming together. This includes, as has already been mentioned, knocking down barriers to demand-side responses.

These barriers exist in the form of control area boundaries, inconsistent and non-cost-based rate designs, inconsistent and egregious loss schedules, and less than timely information dissemination.

The most important element for Ormet and I believe for any end user in any RTO will be knowing that there is certainty over the long term. Ormet looks forward to sharing our experience and hopes that it will be helpful to FERC. Thanks again.

MR. CANNON: Extra points for brevity. Professor Cramton?

PROF. CRAMTON: Thank you. I'm Peter Cramton, Professor of Economics at the University of Maryland. I'm an auction expert and have done market design work in New

England since May of 1998 and more recently in California.

I want to just mention a few lessons and principles that we should have in our heads as we move forward this week. The first is the impossible task of getting it right the first time. We've found that fixing a bad design is a lengthy and wasteful process. So to the extent possible, we want to get as close to getting it right the first time out with RTOs.

Good market design does not just happen. We do not have time to evolve to an effective market design. It's going to have to require careful analysis and learning from best practices.

Getting the prices right is absolutely essential in every market. We've learned that market participants respond to prices. The basic idea of a market is to let the prices discipline behavior, and this works well in achieving efficiency, provided there is sufficient competition.

The good market design is largely self-correcting, but it must also recognize the potential for market failure. And there are opportunities for market failure in electricity as we know, as we get close to real time, competition is often very limited and there's events that will require use of other than just the market to determine outcomes.

FERC's objective in this I believe should be to make markets work better, exercise leadership in identifying how markets can best function and provide the basis for intervention in cases of market failure.

In terms of this morning's panel, what markets should the RTO establish itself and which should be left to entrepreneurs, I think the core is of course the bid-based, security-constrained economic dispatch with locational prices. This includes in my mind both a day-ahead market and a real-time market. The day-ahead market is used to set the schedules where parties make financial commitments but then motivate the physical dispatch. The real-time market is there to respond to uncertainties and price deviations from the day-ahead schedules.

The theory of the bid-based security-constrained economic dispatch is beautiful and will achieve both short-run and long-run efficiency. And it would be nice if we could stop there. But as Roy has pointed out, there's a demand for ancillary services as well to limit volatility in the marketplace and promote reliability.

So these markets, some of these markets also need to be created. And I think that's where the greatest challenge lies -- in making ancillary service markets that do not get in the way too much of the bid-based security-constrained dispatch. And the difficulty with the ancillary services is they're primarily about reliability, and we don't have a good source of demand for reliability that's price responsive and so that we'll respond in appropriate ways in order to promote economic efficiency.

Let me stop there.

MR. CANNON: Thank you very much. Can we open it up for questions? Who wants to start?

(Pause.)

CHAIRMAN WOOD: All right. This last point, and it's one I heard from both the professors here, and I'd like some of the folks here in the middle to think back too. I mean, we've assumed all along that you need the real time. I'm going to use your phrase, Professor Cramton. Bid-based security constrained dispatch market with locational prices.

I just want to see if there's any disagreement that we need that at a minimum.

John?

MR. MEYER: I would just like to say I'm concerned that everybody's attention is turned only to an LMP or dispatch-based system. I guess having operated a system for years, I'm not going to say the system's wrong. It certainly produces a viable solution.

What I'd like to point out that's different, that is a system employed by regulated utilities and one of the reasons it's worked is because of its marginal cost structure only because all the fixed costs of the utilities are already covered. Therefore, they don't have to worry. The free market has to worry, not only recovering its marginal cost, but also its fixed costs and we have a disconnect there where we are applying a method that's set up for having fixed costs all recovered versus a marketplace where they are either partially or not recovered at all. I think we need to keep that in mind.

As far as the system itself, when LMP works, very good, giving nodal prices, it works very good at dispatching the system correctly because that's how the utility does it. It's a system though that requires from nodes to go to hubs, or to a market mechanism such that you can collect the prices in a way markets can trade around.

Where a zonal system actually starts the other way. It usually starts with the hubs, then it works backwards creating rules to make sure that the dispatch constraints are honored, so you're coming at it from two different ways. I'm not sure, in my experience, which is the best. In Texas, we went the other way. In PJM, where we also owned a great many units, we obviously used LMP and it certainly works well too.

I'm not sure I'd be ready to commit that one is absolutely required.

CHAIRMAN WOOD: We'll take up congestion management tomorrow, as far as that particular issue. But as a concept, is it fair to assume that, at a minimum, RTO needs to have a bid-based security constraint dispatch market with some form of congestion management?

MR. MEYER: The RTO must have, in my opinion, a bid-based system to handle the fluctuations in energy. It must have the ability to recognize the security constraints and deal with them, which means it must have the same mechanisms that a bid-based dispatch -- I'm not sure of the exact words that were described -- but the dispatch oriented system would have. It has to have the state estimation of all the buses, the load flow, the power flows, to deal with the congestion and it must have a congestion system.

And the person I believe in charge of the congestion system whether it's covering one control area or several, it simply needs that authority, I think, to maintain reliability.

CHAIRMAN WOOD: Does anybody disagree that that, as a concept -- I think FERC said this in its Order 2000 -- I mean, was there anybody back then that disagreed that that shouldn't be?

DR. SHANKER: There must have been somebody.

(Laughter.)

COMMISSIONER MASSEY: Would anyone make the case for a system that was not security-constrained?

(Laughter.)

COMMISSIONER MASSEY: I guess I don't understand why that's even an issue.

CHAIRMAN WOOD: I focused more on bid-based.

DR. SHANKER: It becomes an issue in the sense that --

COMMISSIONER MASSEY: Can you explain what that means, security constraints?

DR. SHANKER: Sure. A good example might be the transmission lines into New York City or between New York and Long Island. New York-Long Island, I think there's three major lines. You don't load them all up. You could and we would probably get a cheaper solution, but you want to be able to have the system keep operating if there was a failure. So you load them up so that one of the lines can go out and the two others can carry the remaining load. That's a security constraint, an operating contingency that you honor.

You see in the commitment of units in terms of spin, you want to have enough capability, you want to have some criteria for the loss of a generator and the loss of a transmission line, something that allows the system to continue to operate. With that contingency, or that loss of generation occurring, you can strain the system and dispatch around it. That usually means you have additional resources running.

I don't think anybody reasonably would say you don't honor those kind of contingencies. But when you have an organized fashion of recognizing them in the pricing of the system and dispatching around them, or consistent with them, it's used to set the prices. It means real time. We can talk about schedules a day ahead and everything else, but real time, as the load varies, the generation varies, the lines themselves, contingencies occur, line outages occur.

Only one person can see that and that person has to be able to coordinate all that information and adjust the generation and in doing so get a consistent set of prices and information conveyed to all the market participants.

MR. MEYER: I don't think I was saying, I don't believe, in security constrained dispatch, I was commenting whether you need nodal-based pricing versus other methods of pricing. Everybody's got to rely, as Roy Shanker is pointing out, on that system, or you will have situations where contingencies can give you unreliable solutions.

CHAIRMAN WOOD: I'm going to ask an ancillary service question too. The two professors seem to indicate that that's more of, I'll put words in your mouth, political accommodation than a market one. Is that true?

DR. SHANKER: No. I think, again, you could have none of these contingencies honored and you could just have when someone turns on their lights, you know, the generator responds somehow; maybe it does and maybe it doesn't. And you ignore all of these things. Nobody's going to argue for that.

We want a reliable system. We want a system that can handle a lot of variation but the notion that I'm trying to get at, when we call to say these things this way, is that we have a theoretical model but sort of really the extreme no one is ever going to use, but it helps you organize your thoughts about what you are doing when you make the system more reliable by honoring contingencies and honoring reserve requirements and worrying about voltage schedules.

What you do is, in general, you turn more things on. That's sort of a generic response and that's good. I mean, we like the fact that the lights don't flicker all the time, and that they don't go out when a large user, like Ormet, turns on or off. We want a system that can handle those kind of variations, but it has implications in prices. John's concerned about well, we've got to make up fixed costs. Well, let me turn on additional items and depress prices. That has an implication on whether or not you're going to recover your fixed costs. We need market mechanisms around that say I want these people to stay here to turn on and meet reserves, so I want to be sure they get paid in a fashion that's consistent with keeping them in the market in the long run and spot prices alone won't do that when we start adding all these other things on top of it. That's where you start to worry about how do I make up all that additional money.

PROFESSOR CRAMTON: That's the fundamental question. How much reserves do you need. Where's the demand for service coming from. We've got rules of thumb that come from the regulated utility days and the question is, can those be transformed into rules that make more sense in a marketplace that will respond to prices just the way market participants are responding to the energy price. Then the market design challenges, with respect to reserve markets, are much greater than with respect to the energy market.

Fortunately, it's the energy market that's the most critical of all, and if things are functioning properly, the energy market will dominate and drive the market, and there's things that we can do moving forward to make our reliance on reserves, as we rely on them now, less important, such as demand response. If we can get more of a load demand response, they can provide the reserve function rather than having it all on the supply side.

So I view that as critically important in having a two-sided market where basically markets tend not to work as well when you have one side of the market that's absent, so one side of the market simply is completely inelastic demand curves, which is what we have in most reserve markets the way they're run now. There's a fixed requirement so there's no response at all to prices.

In fact, the energy market is to some extent approximately that now too, and the problems of the exercise of market power, which we talk about on Friday, are mitigated enormously when we can have some response on both sides of the market.

COMMISSIONER MASSEY: Let me ask you a question. The topic of this panel is required RTO markets. Should we require the RTO to operate a demand bidding market, day ahead, and in real time, and for ancillary services, number one.

And number two, is that feasible now?

PROFESSOR CRAMTON: I think for energy, the answer is yes, it is feasible, and it is going to be essential to create markets that move towards full efficiency. I think on the reserve markets, we know a lot less. And I'd be less comfortable in advocating a particular solution in the system for reserves. One thing I do know is, if you are thinking about adding a market, you'd better have a good reason to add it and you'd better get the basic design right so that at least, if there is, say, no market power problem, so things look pretty competitive, then it will achieve efficiency, that it will produce a price that is the right price, and therefore achieve short-run efficiency.

A lot of the reserve markets, such as the ex post reserve markets in New England, don't satisfy that requirement. The market has sort of a basic flaw that it doesn't generate. There's no reason for it to be generating the right prices, and so as a result, it doesn't, and it sort of rumbles along and it doesn't achieve what it's supposed to achieve.

So I think for certain reserve products, such as replacement reserves, one needs to have a longer term market to compensate those that are providing the dispatch flexibility that the RTO needs. So I think fundamentally what the RTO needs is energy and dispatch flexibility with which to handle the uncertainties in both supply and demand. The trick is going to be -- I think the energy we can take care of -- the dispatch flexibility is, to some extent, dependent upon the structure of the RTO itself in terms of its resources. How much hydro does it have? How much demand responsiveness is there?

So I'm a little less sure that there's a standard design that can be applied across all RTOs or all countries in the case of reserve products.

COMMISSIONER BREATHITT: Bill, did you have a follow-up? Okay.

MR. KLEINGINNA: I'm sorry, I'd like to respond to that as to what Peter said, and talk a little bit about

Ormet and the kinds of things that we see as a participant in the wholesale market with respect to energy as well as with respect to real time markets.

The question that I think Commissioner Massey put forth was do we need to have a demand side market, and does the RTO need to provide that market structure?

I'd submit that cutting load and providing supply are basically the same thing. And if you show me a price signal, I'll do what's necessary and make an economic decision that makes sense. We've developed, as an end user, these types of capabilities. We certainly don't represent all end users. We're somewhat of a unique case, but there's certainly the case for large end users like aluminum reduction facilities in the Pacific Northwest, self-supplying reserves, and they do. They self-supply reserves out there.

If you show a aggregated group of end users who might potentially be represented by a market participant or an aggregator, a price signal that says you should cut load in the next ten minutes, these folks will probably sign up to do that if it gives them the right price.

So I'd submit that end users are in fact demand responsive. The demand curve is, I think, a little bit more elastic than we want to believe here. At least it is in my case. Power is an extraordinarily large part of our fixed our costs and we stand ready to make sure that our overall costs say down. And if you show me a price signal that's orders of magnitude greater than what I can afford to make metal for, I'm going to go ahead and cut load.

And I think that as times goes on, you'll see others, who aren't maybe as sensitive as we are, do the same kinds of things, as the price signal is developed.

COMMISSIONER MASSEY: I guess what I'm wanting to know, my question perhaps wasn't clear enough, should these entities that are cutting load then be compensated at the market clearing price for cutting load. They have provided a megawatt of resource essentially which one might argue is as valuable as a megawatt. Should they be compensated for that? And should the market design require them to be compensated?

MR. KLEINGINNA: Well, I would certainly hope to be compensated.

DR. SHANKER: But you don't want to pay twice. This is a problem that happens quite a bit. When I turn off my lights at home on a real hot day, I don't get a check from PEPCO, I fail to pay, and PEPCO actually you know it's like $220 at peak in the summer per megawatt hour. For those of you who don't pay attention to your bills, it's expensive. But's that the price signal.

Indeed not everybody has the infrastructure of a large, industrial user to see the price signal, but what you want them to do is not consume. If they're going to provide an additional service, like if he's going to be dropping load on 500 megawatts of load in ten minutes' notice for reserves, that would be an additional service in the ancillary markets and he should be able to participate and get compensated.

But one of the problems that's come up here is the turning off for high prices seem to be sometimes a good in and of itself, seeking compensation when the right response is, no. What you do is you turn off when you face the high prices, like you generate more when the price goes up, and you generate less when it goes down. There's no second tier of compensation.

PROFESSOR CRAMTON: Of course, if you're full hedged, you would get that compensation.

DR. SHANKER: But then you have already bought it.

PROFESSOR CRAMTON: And you're selling back at a high price. But I think the trick is, if you're load, and you can provide this flexibility on a prescribed basis, then you should be compensated not just in the energy market but in reserves and because that's a very valuable service. It's just as valuable as the generator that can quickly kick on.

COMMISSIONER BREATHITT: John, you had talked earlier, and I think I saw John O'Neal and Roy Shanker shake their heads to a comment that you made, and it went to something like this, that sellers and buyers should see the exact market price after it's settled on.

My question is, did you mean the bilateral market, are you talking about bilateral price transparency? Or were you talking about ancillary services?

MR. MEYER: Mainly I'm talking about the imbalance energy or spot market price. One of the problems I have is, if you don't have a consistent price signal for all, then you're going to have many opportunities for arbitration and other things going on. So what i was talking about is if I'm a load or I'm a generator in a nodal system, I'm a load or a generator at that node. When I'm out of balance, I see the same price.

If I'm in a zonal system if I'm a load or a generator, I see the same price.

COMMISSIONER BREATHITT: The same price as?

MR. MEYER: Whether I'm a loader or a generator, I see the same imbalance price; I don't have a special one calculated for me because that's the price signal we were talking about earlier.

COMMISSIONER BREATHITT: So it would be a before-you-need it price. I thought you said after it's settled on.

MR. MEYER: It's really at real time. It's as close or before real time as you can make it. There are lots of economic arguments. If you get it too far ahead of real time, you have a lot of price chasing which means you have to take other things into account or other solutions to solve that problem. You'd like to stage it at real time.

And as someone pointed out, if you give the price signals, a load can passively come on and off in response to the signals.

COMMISSIONER BREATHITT: Was that what you were agreeing with, John and Roy?

MR. O'NEAL: Yes. Our view is that the load side ought to see that same price signal in real time as the generator does and be able to respond to it and be able to cut back on load.

I guess picking up on Commissioner Massey's point, distinguish between the wholesale supplier the wholesale load who would respond to that price signal and actually get compensated at that price signal, versus say a retail load who ultimately were going to rely on entrepreneurs to go out and sell a demand reduction product, say, to a retail customer. They're going to get compensated in some other form; they're not going to get compensated in that same real time price. They're going to price that whatever way they think they ought to be compensated for. So I guess I'd make the distinction there at the wholesale level versus the retail level. But, yes, absolutely, the load ought to be able to respond to that real time signal as well.

COMMISSIONER BREATHITT: But it is easier, you say, if you are a large user than a residential; someone does that for you.

MR. O'NEAL: Absolutely. I'm not sitting at home thinking about turning down my refrigerator. When prices are $220, as Roy points out.

DR. SHANKER: The other side of this is the logistics of doing it on a residential system are expensive and it's not cost-effective. I could have my refrigerator shut off, you know, when prices got above whatever, assuming that I could see them, which for the most part, people cannot see real time in residential use. I could have the software to do that. I could have telemetry. The logic is not tough but it's expensive, at least in the context of someone whose electric bill might be $100 a month and you're talking $500 of equipment. It's just not practical.

Large industrial users, this kind of metering is already there. The infrastructure's there. Most of them, if they don't have direct pricing capability from their utilities, they usually all have direct lines, it's not unusual to see those people being able to respond real time to real prices, and that's a very desirable goal.

CHAIRMAN WOOD: I'm going to ask David Hadley this. How do we think, you know, this is kind of in that fuzzy ground between the retail function, which is say, a customer like Mr. Kleinginna's company, a large C&I customer perhaps, if we just assume that your points about residential, at least for the short term, are true and they're not in this market, but the bigger guys that do have the telemetry and all that are, how do you interface that kind of wholesale market resource with what is at the end of the day probably a retail rate tariff for that large customer?

How do we kind of bridge the retail and wholesale jurisdictions there so we can take advantage of this resource but also respect the retail ratemaking authority of the state?

MR. HADLEY: That might very well be a good question for a task force to jump into.

(Laughter.)

MR. HADLEY: I'm finding the discussion probably as interesting as I'm sure you guys are. As a policy person trying to follow through some of this, one of the parts that kept coming back to me on the bigger picture of that, Mr. Chairman, is hearing the terms that markets are self-solving if markets worked properly. But at the same time, recognizing that there are market failures. And when those times happen, it gets at the crux of the design that I think we're listening to.

When I heard the doctor at the end of the table discuss dispatch flexibility, and then I tied that with the other end of the table talking about security constraints, part of dispatch flexibility is the insurance that when you need to dispatch that there is a line to dispatch it on. And we've heard ad nauseam about certain experiences in particular states and meltdowns because of not sufficient enough generation supply, along with a whole host of other issues.

But the same is just as true, if you have an adequate supply of generation but aren't able to move it through the wires because of constrained systems, you do not have that dispatch flexibility that's necessary. That was part of my comments. For your involvement or the state involvement, you're a market monitor because you might not have a sufficient amount of wires, but if there is some manipulation of the system, the wires might as well not even be there if there's an artificial constraint created through dispatch.

So I think if we're going to be able to have any kind of tariff that makes sense, we at the same time have to ensure that the system is there that allows the free movement of that power. That's where I'm back to there is a very real need even in a deregulated system for regulation and policing.

We welcome and look forward to Michael Jordan coming back on the basketball court, but if there's not somebody in a striped shirt out there helping that system work, everybody can't play to their full potential. So I think that's the real key to your question and to what I'm hearing across this table.

COMMISSIONER BROWNELL: David, getting to your point on market monitoring, I think you are suggesting its importance but you're also suggesting that maybe we reconfigure it a little differently. Are you suggesting that the market monitoring units ought to report directly to the FERC and the states or be external organizations that go in and monitor. What is it exactly that you have in mind? I agree with you that that's the importance of market monitoring of course is it grows every day.

MR. HADLEY: I guess as I take part of the concept of independence for RTOs themselves and their governance structure to create the whole market design to have comfort and assurance that those designs are there requires independence from my way of thinking, Commissioner.

Equally it's true that if we're going to have someone monitoring the markets to give all participants confidence in those systems if they are directly responsible to the RTO itself. Would that chill, so to speak, some of their investigation, some of their activity, without impugning any of the market monitor's credibilities? It just seems to be a system that's not quite as open to the point that if they feel they find some issue in a judge's recent terms "hanky panky" going on, are they comfortable with responding to the appropriate authority, if it be this Commission or a state commission or some other federal authority.

I think the structure should be that they would have that flexibility without the chilling effect of first having to get some sort of clearance in some fashion from the RTO itself.

COMMISSIONER BROWNELL: Thank you.

Peter, you spoke of needing to design and work around what will be inevitable market failures. Those are kind of chilling words for those of us who've lived through the last couple of years. Would you say more about exactly what you mean, exactly how we define a market failure as opposed to an imbalance in supply and demand, something that basic, and then would you talk a little bit about how we design around that.

PROFESSOR CRAMTON: Yes. First of all, designing around it is critical because we can make market monitoring much easier, that is, almost make it something that could be accomplished effectively if we had a very good design. Its role becomes very important if we've got markets that don't make sense, they're sending the wrong price signals, they're just ripe for gaming. In fact, the participants are almost obligated to game poorly designed markets because their purpose is to represent the interests of shareholders. They have an obligation.

So I think getting the design right is the most critical aspect. The kinds of problems that one can have, well first from poor design but second from structural problems such as excessive concentration in one of the products for which there's a market, whether it be energy or ancillary services, and that has to be addressed either with must run regulation or ideally a structural solution such as divestiture. And I think when there are transactions of generating assets, that this is something that has to be looked at very carefully because the transactions go through that lead to excessive concentration. Then it's very difficult to unwind them.

But that's one area that will have to be continually watched. A good market design, we did say, is self-correcting and one element of a good design that you see in the bid-based security constrained dispatch is the uniform pricing where everybody does get paid; if they provide a service, they get paid the same price for that service. That is actually desirable in terms of this self-correcting feature because if you're facing a uniform price market and in a position to exercise market power, the way you exercise that market power is by, if I'm a generator, say, withhold supply which in essence is making room for my smaller rivals, so it encourages the response of exercising market is to encourage entry which is the right competitive response to solve the problem.

So that's one example of the kind of forces you'd like to see at play in an effective design.

DR. SHANKER: I think I'd like to take a slightly different view of this. You need to distinguish between a good design and how you mitigate if there's a market failure. The mitigation process is important and needs to be understood and well done but I think it is probably going down the wrong path to see it as a part of market design.

A good market design makes visible, as easily as possible, market manipulation; it doesn't stop it. There is no market design process that I am aware of that can stop or truncate market power. If it's there, it can be abused, and it can have undesirable results. A good market design hopefully makes things transparent enough so that you can see this happening and decide to do something. Once you decide what to do, you may want to take actions and mitigate in a fashion that is compatible with your overall market design. But it's a mitigation process.

You are probably aware in New York City, there's a reasonably tight supply situation and their conclusion is that under certain circumstances, there will be market power. Inherent of the dispatch of the system, when certain conditions are met, people are cost-capped, that's a mitigation. But the underlying market is transparent. In fact, the conditions when this occurs are seen clearly through the prices that result in the day ahead market and that triggers things.

PJM has similar types of responses when they see similar conditions being met with respect to load pockets of units, or switched into a cost-based bid as opposed to a market or an open bid. The market design process is the mechanism for seeing what's going on. The mitigation process is external and can be quite varied. We fight a lot about that in the various markets. We all have different views about when it's really market power versus scarcity and whether we should be doing something.

But there are two different steps here and they shouldn't get mixed too closely together or I think it'll start going down the wrong path.

MR. MEAD: I heard several of the panelists earlier talking about the problem in a bid-based market of generators, especially the generators on the marginal recovering their fixed costs. I heard the problem but I'm not sure I heard any answers.

In a market that's competitive where no seller has the ability to influence the price and presumably if it's bid-based, you would expect these generators to be bidding something close to their marginal cost.

You know, how do you get a price above marginal cost for those marginal generators so that generators, in the long run, are recovering their fixed costs, and you get entry and have all these good things.

DR. SHANKER: There's a couple mechanisms. Ideally, we would have sloping demand curves and the shortest costs would pop up. We'd have clearing markets and we'd be done with it. And load getting off the system would set the opportunity costs and we could just all walk away. That doesn't happen and in fact, because demand is basically inelastic for the most part in the real time markets, we have the potential for very, very high prices. So we ministerially deal with that by price caps.

So when that happens, you're again keeping the market from clearing, you're not getting to see the full shortage costs, and you've got to create a mechanism, in a sense, almost another ancillary service, you've got to create a mechanism to collect the money and there's different ways that it can be done.

Some of the vehicles are reserves. Some of the most obvious is an ICAP market, an installed capacity market. I look at installed capacity as almost a residual ancillary service. It cleans up all the rest of the missing money I talked about when you're done with clearing all the other markets on top of it.

And if there is sufficient scarcity rents or compensation in the other markets, ideally, you would see ICAP clear at zero. But to the extent that we've truncated the markets and you have kept people from collecting the shortage costs or the sufficient shortage costs to keep generators in the market, that becomes a residual pool of funds that people compete for and it sets a clearing price to keep people in. And it is those missing moneys that you always have to be concerned about.

So the answer to your question is the ancillary service package, as a really broad view of it that I take, including installed capacity, are the mechanisms for making up the missing money, and that's how you do it, and you allow the opportunity for the markets to clear on that.

MR. MEYER: Let me take a stab at it. I pretty well agree with everything Roy said on that. But one of the things I want to point out is that in the right functioning market, as he said, the price will go up as the goods become scarce. If they don't go up and the marginal unit can't recover its fixed costs, he will get out of the market. He will basically go bankrupt. He will leave, exit the market.

You have to allow for that. We are not quite used to allowing for that because this is a different scenario we're coming out of. A regulated utility that really guarantees the fixed cost too, but if that person can't recover his fixed costs, he has to exit the market. That's his choice.

I guess the other point I want to make is that load needs to see the price. That's probably the biggest issue we have here. The markets that have failed miserably is because there's a big disjoint between the wholesale market and the retail market. If that's sustained over a long period of time, you will have a huge market failure.

PROFESSOR CRAMTON: That's the point I want to make. I agree basically with what Roy said except for the focus on missing money. It's not just missing money, there's also the market failure of the unresponsive demand. In fact, people would be responsive if they had the technology and they could see the price. They'd be happy to. We just haven't evolved to that point. So that's why it could well be that there's actually an enormous surplus of money and the difficulty is we don't know how much compensation we do need for particular sorts of resources that we seem to value in a particular market.

So I think that that is the greatest challenge is really with respect to the reserve markets and the ancillary services having something that's market driven rather than simply based on a requirement.

MR. MEYER: I'd like to just make one other comment. What I was really referring to is the retail market, whether it sees it in real time or whether it sees it over a long period of time, will respond, and a good example is just gasoline. Gasoline, when it goes to three dollars, what happens to the demand for it? It sinks by 20 or 25 percent. It drops out the other end.

Electricity may not be that elastic. We don't know because we've never really let it go to see how elastic it is but I guarantee you it has quite a bit of elasticity if you let the price fluctuate.

The other thing, as far as the markets, I would agree with Roy. The ancillary service market is a good market. The ICAP market, if you're worried about maintaining these generators where you start getting tight supply, the ICAP market is a good market because it gives the money and it requires them to bid in.

PROFESSOR CRAMTON: Let me take issue with that. I think the ICAP market is a holdover from the rate-ofreturn regulation days. It is not, I don't know all ICAP markets, but the ones I'm familiar with are really nothing more but an opportunity; it's not providing a service that's valuable to the ISO, and it's not sending the right price signal. In fact, it simply represents another opportunity for parties to exercise market power in certain instances.

I think with ancillary services, you need to look very carefully at what the ISO finds valuable or the RTO finds valuable and why, and then be a smart buyer and buy what is valuable at prices that make sense and don't have an artificial market that has little relationship to reliability.

DR. SHANKER: I'm probably on the complete other side of that. If you're willing to remove price caps and get a clearing market, which I don't think we can have, I think it's a non sequitur because of the level of inelastic demand, but if you were, you can get rid of the ICAP markets. But the answer here is that we know the political reality is you're not going to accept that. You're not going to accept market-driven inadequacy. You're not going to accept the situation where it takes two or three years for new entry to solve scarcity problems. We just know that. We don't have to go down that path again.

It's like Lucy, Charlie Brown, and the football, you can tell me you're not going to cap the markets. You can tell me you're going to allow a market response. And the minute the shortage is there, and the prices go through the roof, you pull the football away.

(Laughter.)

DR. SHANKER: That's going to happen. So let's get by that. I know, and I have no great insight beyond this panel, for sure, about what regulators are going to do when they see these situations of scarcity, and it is not going to be come back in three years and tell us about all the new entrants, and don't worry about it. It's just not going to happen.

So we need mechanisms that essentially reflect the social judgment that we're taxing participants that have surplus supply in the market and that surplus supply is mandated through something like ICAP. It's effectively a tax. You're telling people, I don't care what the market wants, I want extra.

I know that's going to suppress the prices, but that's okay, and we're all going to pay for it through something called the ICAP payment. As a separate function, if you don't design it right, I agree; we have market power issues. But you've got to keep separating market power from the functions that you want to occur in the market.

Do we need monitoring? Do we need divestiture? If we need other controls and other mitigation mechanisms, you've got to do that, but down throw away that we're going walk out of here with everyone saying don't worry, adequacy will take care of itself, because it's not going to happen.

MR. MEAD: Can I jump in a little bit? What I've heard so far is that in order to allow for recovery of fixed costs, especially if you have an elastic demand and you can't rely on blatant moment-to-moment clearing of the energy market, you need an ancillary services market and maybe or maybe not an ICAP market, but there's a concern about market power, especially when supplies are tight.

Is there something -- let me address this to Professor Cramton first and then others can jump in -- is there something in the design of the ancillary services market itself in terms of relations to energy prices or the way the supply is offered that would allow this competitive recovery of fixed costs to take place? You know, how do we address the market power issue and ditto for ICAP.

PROFESSOR CRAMTON: Yes. The problem I have with ICAP is basically I agree with Roy. As long as you establish an ICAP that's valuable, a product that's valuable. In New England, it doesn't have to be able to turn on except for once every six months to be installed capability. And so how much value is the ISO getting from dinosaur resources that probably wouldn't turn on if you ever did need them, and then the market simply becomes an accounting exercise to follow money among participants. And it really is then all about exercising market power rather than in rewarding people that are bringing valuable resources to the marketplace.

Now, New England is in very great need of quick start resources, so what I'd like to see, now that dinosaur resource that turns on one out of 20 times but happens to come on every six months, if you really push it, is getting paid the exact same price per megawatt of capacity and this wonderful quick start unit that turns on whenever needed, because there's some sort of contingency.

So fine, pay for extra capacity. We do want to pay for that extra capacity but define the products so that they are something that are valued.

MR. O'NEAL: Can I comment on that? I guess what I heard there is in fact both the short term and maybe the long term capacity market does make sense. But it's defining it correctly, and it's really an issue of defining what the products are.

It goes back I guess to one of the original questions here. What products do we think ought to have standard design, and I think certainly you are hearing some agreement that there ought to be some standardization regarding the short-term products, the regulation spinning reserve and the non-spinning reserve and then the question is, how do you design the longer-term market? Because we have price caps, how do you design a longer-term capacity market to incent new generation to enter the market?

MR. MEYER: I was just going to say the ICAP market, in any of the products, you need to understand what your goal of the products is for. How is it going to be used? What do you need it for? PJM, one of the beauties of their short-term ICAP is it basically secures their capacity supply to bid back into the market. So it guarantees they're going to have supply in the short-term because they have an unbalanced load schedule. They need that.

In Texas, that wouldn't be very valuable because it's basically a captive market. They're not going to sell except into the market itself. In other places in Texas maybe, we need to look at two or three-year out ICAP market. If we try it now, it should be almost zero because we have large amounts of reserves as far as pricing. But I think you've got to tailor it and you've got to design the product right or you're not going to get the desired result. That's the key element in any of this.

DR. SHANKER: To try and answer several tiers of what David asked, the first thing is if you have a bad market design and you don't have to perform to get the ICAP payment, it's sort of stupid, so I wouldn't want to fight that. But if you have performance criteria and you have obligations to bid into the market, and you penalize people for non-performance, at least not in terms of a penalty, but you make what they have to sell worthless, then you have good steps towards fixing that.

In terms of I thought the first part of your question was, how do you clear, how do you improve the likelihood of clearing the market so that these moneys, these fixed moneys to keep these marginal units, marginal energy units take place, I think it can be done in several fashions, and we see in the Northeast some good examples of alternatives.

I think New York probably has the right theoretical design in terms of the reserve markets. In terms of availability payments or people participating and it gets a marginal price signal for somebody being available the next day to be called on for reserves. That tracks performance a lot closer to what you're actually buying. I think that's John's point. They want it to be there the next day.

PJM does the exact same thing but at a little grosser slice. PJM says if you're in the ICAP market, I've got a call on you end day, the next day, so I don't have to make a separate payment, okay. Both create mechanisms to recover that. I'll say it again, the missing money, both create mechanisms to get that marginal money up, to get that fixed cost staying in money up for the marginal unit, and there are slightly different efficiency signals.

The New York price signals says the guy has a little bit better n-day spin resource of a quick start unit and might get a little bit more money out of that. PJM it might all show up in the ICAP market.

We can argue that over the long haul, a different set of generators will survive and we'll have different people adding a different mix of resources and we'll have a slightly different efficiency argument or efficiency characteristics. But we've created two mechanisms there, n-day payments or day-ahead payments, or longer-term payments to create that pool of money for someone.

And we can look at almost all, we can look at Blackstar, which is probably a cost-based kind of service, but we can look at that as a pool, and we can do the same thing for reactive schedules or reactive payments.

And what we want to do is pool all these things together and sync them up because they have to be coordinated so it gives you an opportunity to clear the costs you're concerned about but also to complete the clearing process, whatever is the residual payment, the one at the end, that one gets competed out. That's why I'm saying you want to make sure these are all coordinated. There's lots of flexibility within the pieces, but they've got to be coordinated and allow that last step to compete out the residual.

MR. CANNON: We've got about an hour left here. I don't want to break up the rhythm we've got going here. Some of the discussion is really good. But if people need to use the facilities, including panelists, please feel free. I'd like to get Staff to sort of start focusing in on some of the questions, because I'd like to try to get to answers to some of the points that we haven't gotten to yet.

MR. O'NEILL: John, you mentioned that we would get back to flowgates at some point. So I'll help you get back to them. Should it be our objective to attempt to design these markets so that the customers have lots of choice in terms of the products that they can buy? For example, there are zonal aggregations that are completely consistent with LMP. There are LMP markets where hubs are designed for trading and you can choose which hub you want to trade at. There are market designs where you can choose either flowgates or FTRs or a combination of both, and there are markets where you can choose to either bid into the market or schedule without bidding. Should that be a goal of these mandatory market designs, giving the consumers choice as to what kind of products and how they want to participate?

MR. MEYER: Well, when you say give consumers choice --

MR. O'NEILL: Customers.

MR. MEYER: Good. Because most of these you've described are wholesale issues.

MR. O'NEILL: Wholesale customers. We sort of divide up here.

MR. MEYER: Yes. Definitely, the market needs to be tailored to whatever spot markets or ancillary services, they need to be tailored such that they make robust forward markets and other things for the marketplace to see and to trade around. Otherwise, I think we've pretty well failed if we just simply try to re-create a utility scenario.

That I guess is my earlier point. I think we need to look at innovative ways, not just bring the same utility information and ways to solve things into it. Somebody mentioned TLRs. That's a utility solution. That's not a market solution.

MR. O'NEILL: That wasn't one of my customer choices.

(Laughter.)

MR. MEYER: But there's a lot of them along there. Congestion management, to me, you can go either way, LMP or flowgate. I'll probably catch a lot of argument over that.

MR. O'NEILL: Can you do both?

MR. MEYER: Can you do both? Well, when you solve local congestions, in some way you've got to both.

The beauty of LMP I think it helps solve local congestion issues. But then you have to aggregate it back toward hubs to trade around, because nobody wants to trade a thousand different points in a system. It would be almost impossible to give a product like that or a set of products.

The other way you create it around the hubs or where it's more tradable, still respecting the security rights, the constraints, everything else, but then you have the local congestion problem, and if it's not a major issue, it can be solved fairly easily, like we believe we can in ERCOT. We think it works just as well. Plus everything we do is flow-based anyway. It's not contract path or anything else.

So we pretty well know where the flow is going and respect all the rights of dispatch up front. So I don't know if I've answered your question quite right.

MR. O'NEILL: PJM claims to have the most liquid or maybe second most liquid, depending on how you count, hub in the world. Is that the type of hub we're talking about?

MR. MEYER: I don't know if it's the second most liquid hub in the world. They've been around a long time is all I can say.

(Laughter.)

MR. O'NEILL: It's their claim, not mine.

MR. MEYER: Certainly Palo Verde is one of the more liquid ones that I know about, and it doesn't have anything to do with the nodal approach.

DR. SHANKER: I'll try and split Dick's question into a couple of pieces, and I think it complements what John said. If you think through the pieces of his response. You can have a variety of forward markets. You can have them for hedging, you can have them flowgate oriented, you can have them LMP if you want, and you can have FTR structures, if your flowgate is zonal or not, and they all would be compatible in some form. And that becomes the big issue with a clearing spot market with locational prices that we discussed.

The issue tends to be in the tradeoff that John was talking about. If we had something that was flow-based and we had the financial rights for that, we might find a solution where it's not exactly feasible, and that's the internal or the local congestion he was talking about. Now it's a real simple question is who pays for that? And that's a design problem. And if it starts to be large, which is one of his other comments is, if it's small, maybe we can live with that and find some facility with that market design. But if it gets big, we still might be able to live with it if the right people pay for it. And if it gets big and the wrong people pay for it, we have a real problem.

So one of the things that you're trying to do in balancing these choices is whether or not you're setting up a forward market that integrates with the real time market in a fashion that results in a lot of uplift or potential infeasibility for what you've sold. And it's that balancing question to the extent you set it up, at least the two alternatives we've seen lately is, what's the likelihood and the magnitude of that infeasibility? Do you think it's going to be small? You can probably tolerate a lot.

My view is that even if you think it's going to be small, eventually it's not going to be small, and so why set yourself up for this problem later on when you've put in place a lot of institution and trading mechanisms that aren't going to be real flexible in solving that?

Are there other vehicles? Can we do them simultaneously? Yes. Can we create an FTR market as a basis and then let people trade flowgates on top of them? Absolutely. Then the infeasibility risk would be taken by the external markets. You know, people setting up private markets to trade in those rights on top of something that we at least presume to be feasible in the first place.

MR. KLEINGINNA: I'd like to address this issue as well. As I sit in Hannibal, Ohio as an end user and recognize that the PJM is the most liquid hub in the world, it doesn't do me a lick of good.

(Laughter.)

MR. KLEINGINNA: And it's not that far away. The reason is because I don't know the rules. I don't know how transmission is going to move across PJM and into AEP, into my bus, okay? That's an extraordinarily difficult thing, and we can talk in nice ideas and nice platitudes about how we're going to have forward markets. But as a practical matter, if I don't know the rules of the game, and I'd submit that if they aren't relatively standardized, then it's very difficult for me to say in ten years I'm going to buy this power from you at the PJM hub.

And, you know, my experience is in the gas business. And the gas business has one hub, one physical clearing hub. It's at the Henry Hub in Louisiana, and I can hedge at the Henry Hub and buy basis in a market to my bus. The reason I can do that is because the rules are abundantly clear as to how power moves in the interstate natural gas market. They aren't abundantly clear in the electricity market, so that I have a hub at Synergy, which is relatively close to me, and a hub at PJM, which is relatively close to me, and if you ask me, Mark, well, in 2005, where are you going to buy your power? I'd say I don't know. I don't know the answer to that question because the rules aren't standardized.

Does that speak to flowgate rights? It may very well. Does it speak to FTRs? It may very well. Does it speak to an overall market clearing price for the Midwest, we'll call it the Midwest ISO, for the Midwest RTO when we've got these guys working well together? It might. But my concern is that we have a structure that my natural market I can find what I need to do long term, and I can figure that out, and that's really the fundamental issue for me is how do I get certainty with respect to that?

MR. MILLER: I can tell that we're going to have a lot of carryover on a number of panels, because we're talking about congestion management. This panel I think is supposed to talk about mandatory markets. And the only market of which I am aware that the Commission has talked about being mandatory is access to an imbalanced market.

So let me ask you a question. I heard I think almost uniformity across this panel that there should be -- the RTO should run a spot market, a real time market, should run a market for ancillary services, depending on how you couch that. And ancillary services in some way is going to deal with the reserve issue for future payment.

MR. KLEINGINNA: I'd like to push back on that a little bit. With respect to the RTO needing to run a mandatory spot market, that's fine if I don't have to participate in it. And I don't have the costs that are associated with ICAP because for my load, I might not need

ICAP. I might not need ancillary services. And if, as Commissioner Massey suggested, we have a market wherein I can use load to meet my reserve requirements and avoid what could potentially be a non-cost-based or an inflated-cost-based type of ICAP charge or type of reserve charge, then I would agree that the RTO can and probably should offer it.

But from my perspective, I want to make sure that I'm not priced out of the market because of the way the RTO happens to -- I want to be able to go out and hedge that. And if I'm hedging it by load, by agreeing to shut load down, or hedging it by agreeing to be off, or hedge it by going to a third party and saying I'm going to get my reserves from you rather than expose myself to that day-ahead market, I would agree that the RTO can provide it. But if I'm going to be inflicted with a gun to my head saying you've got to pay for these reserves and you've got to pay for this ICAP, I would disagree vehemently that that's the case.

DR. SHANKER: I think most of the designs that we're talking about allow for self-supply, and they would allow for bilateral agreements. We might argue about whether or not somebody in that situation -- clearly, if you're interruptible, you wouldn't be in an ICAP load, but we might argue about whether somebody in that situation consumes reserves or not. But I think all the designs we've talked about, at least at a generic level, would accommodate what your concern is.

MR. MILLER: One other point that was made, and again, I emphasize we're talking here about mandatory markets, and in my mind, I'm thinking about something that's mandatory across RTOs, that's standard, that is somehow standardized, at least within interconnects, I think it was Dr. Cramton you mentioned the day-ahead market. I want to know if -- you seem to feel that that should be a mandatory market, and I'd like to know if anybody else feels that way too.

MR. MEYER: I assumed the day-ahead market referred to is an energy day-ahead market. It depends a little bit on the market design I guess before I make a commitment. If you have unbalanced schedules, it has a place. If you have balanced schedules, I don't think it has a place. It just depends a lot on the rest of the market. I think you've got to have day-ahead ancillary services. You can self-arrange them, at least some minimum number. My minimum set I think I mentioned is spinning some sort of ready reserve or nonspinning and regulation.

I guess regulation could be a sticking point if you have multiple control areas where the RTO requires it or each control area requires it. I guess our preference is there should be a single control area, though a few might do if they're arranged properly. I think, you know, there's different scenarios of that.

Also other features. I mentioned the planned reserved market I think has some value. You have to design it right or it will be just a waste of money, as someone pointed out. The functions I haven't heard, I don't know if you call them markets, but we've heard them mentioned a lot of times. It's transmission planning and construction are just intimately critical to the RTO and him directing that such that the system is reliable and not a function of just whoever wants to build at what time.

And I guess last, the others will talk about later, congestion rights. I think he has to manage and administer the congestion market.

MR. O'NEILL: Can I get a clarification? If you deliver a self-schedule into the ISO or RTO in the day-ahead market, you can opt out of being in the day-ahead market so that it becomes an optional market in a sense that even though the RTO runs it, if you want to schedule yourself in, you don't have to take the consequences.

MR. MEYER: I think that's true to a degree. I think we need to be careful. I assume you're talking about a bilateral market where you can self-schedule. But if you're using the transmission grid and you have a basic set of services required for the transmission grid, you need to share in that price also if you serving at your own point, your own load and generation behind your meter, I would agree, you shouldn't be charged for it.

MR. O'NEILL: I would assume in a broader sense, a self-schedule would include transmission rights. And if you don't come to the market with transmission rights, you're going to have to pay the transmission charges.

DR. SHANKER: You'd have to do that.

MR. MEYER: I think load, if you're a network load customer, you have to pay transmission rights. If it's point-to-point int hat scenario, they're going to pay or their supplier is going to pay transmission rights.

I think one of the issues is whether that bilateral schedule is open or exposed to congestion cost. And my answer would be yes, unless they have the FTRs or whatever we want to call them, some sort of hedging protection.

PROF. CRAMTON: Another issue with the self-schedule is really is it the wild West where they can do whatever they want whenever they want to, including the last nanosecond? That's not what we want. That's why I view the day-ahead market as important. If you're self-scheduling, you're participating in the day-ahead market, you're simply participating as a price taker. And you're fully hedged. So it's presumably with a bilateral contract. That's why you're wanting to self-schedule. But there has to be an obligation to report the self-schedule on a day-ahead basis so that the resources can be appropriately scheduled for dispatch in real time.

DR. SHANKER: Looking at the pieces again, why do we have the day-ahead market or why do we have the discussion? It's a security issue. We're looking around and we want to make sure that things are turned on for tomorrow. That seems like not an unreasonable practice.

We can do it in a couple of ways. We can mandate that the people have balanced schedules, which is sort of inflexible and probably is inefficient. We could say, you can have a self-supply or submit a bilateral if you want, and the rest of the people could bid in. That certainly would be my preference for a structure for this.

But the overall goal is that somehow when the smoke clears, we're looking around to see what we think tomorrow's load is, and we're going to have the system operator say, gee, I want to be sure that there's enough some way quick start committed units or whatever so that the system doesn't crash with the loads tomorrow, and we're back to the question of what's an efficient way to communicate that information. Do we just let them pick randomly? Do we let people self-schedule? Do we mandate that they self-schedule? Or do we want to create a market around that so we can have economic communications about what are the alternatives for either self-scheduling or bidding resources? You could do it other ways.

It seems reasonable, and I would agree with Peter on this, that a reasonable conclusion is that you'd like to see a day ahead commitment process that is also economic. It doesn't have to be that way, but it sure makes sense to do it that way.

MR. MEAD: There was a point made earlier, and I think several panelists voiced agreement that in the real time market, suppliers and demanders should see the same price. I'd like to sort of pursue that for another moment. I've heard some arguments made in various places that load who shows up in real time that didn't schedule it in advance sort of creates the need for some extra ancillary services, and there's a cost to that. And therefore, that the price that buyers in the real time market pay perhaps should include not only the real time energy price but something more to recover those extra ancillary services.

And not only that, but if loads start doing things that are wildly different from other schedules, that this creates reliability problems. Perhaps there should be some penalty associated with that on the supply side. I've heard arguments that, you know, a generator that has submitted a bid to the grid operator in advance and is performing an instruction makes it easier for the grid operator, whereas some wily entrepreneur that just tries to chase the prices is again creating operational problems that perhaps should be penalized. Could I hear comments on these issues in terms of the basic question about whether all suppliers and all demanders in real time should see the same price?

MR. O'NEAL: I'll take crack at that. I think my view on that is you're procuring those ancillary services to provide for the reliability of the grid in real time. There's a lot of reasons why in real time things aren't matched up perfectly as you planned when you went into them today. So it is because load is different, weather is different, different users turn on or turn off what they think they're going to need. But generation is also different. Units are not perfect. We like to think they're going to run the way we say they're going to run, but in real time, things are often different.

I think our view is that you ought to allocate those costs to those folks who do deviate from the day ahead schedules and you share the cost of buying that certainty for having those other resources on board to have reliable markets, you share those costs to those who deviate on the load side as well as those who deviate on the generation side. Both sides of the coin.

MR. MEYER: I think I probably brought the issue up first. As far as ancillary services, I think in Texas we did get something right there. And there, the obligation for ancillary services are assigned to all load that use the transmission grid. I'll go back to that. Obviously, if an industrial is self-serving, and that means that they're serving their own load behind a meter on a nonpublic transmission system, then they would not be tagged the same. But any other load would be tagged for the ancillary services, and it's based upon a historical, not a schedule itself, sharing approach.

So, therefore, if they're up or below or whatever, they're going to pay a historical prorated share of that. We can talk about what's the right timeframe. There's a lot of issues there. But I think what we're driving at, though, is that load and generation, if you're going to have load bidding into the same markets or even trying to respond to the same markets, they have to send the same price signal. They've got to have certainty. And that's probably the biggest issue we have there.

MR. MEAD: Just so I understand, so you would allocate ancillary service cost to a load but not to generation who deviates from the schedule? Did I understand you correctly?

MR. MEYER: That's right.

MR. MEAD: And why?

MR. MEYER: When I say "ancillary", I mean the capacity cost of ancillary services. There's usually two components to ancillary services. One is pure capacity and one is energy. The energy is usually settled at the real time price when it's deployed. It doesn't have to be. There's other markets where it's settled differently, but a lot of times it's settled there.

The ancillary service capacity basically is for load service. Maybe you're asking the question, what happens if generators cause imbalance? Well, what are the cases that they cause imbalance I guess is the question. One is they could be under schedule, which means they probably have capacity and for some reason the price is cheap and they don't want to generate. To me, that's as legitimate as a load saying, hey, the price is high, I want to turn off, or if I have a process like an arc furnace or some process I can increase if it's real cheap, I may want to go up in load, as fast as I can.

So I think you want to send the price signal and let the load and generation follow it. Now your issue of price chasing is one we dealt with a lot, too. To me, if you're price chasing that helps the RTO, there's nothing wrong with it. In other words, if he's deploying regulation in the same direction you're following the price, you ought to get paid the same thing. If you're opposite of it, though, there probably is a point where you either get paid nothing or you get paid only a small fraction because now you're hurting the system.

So now you're paying back the system, if that's what you're asking. So it's a little more complicated than just saying that the generator off schedule pays ancillary services I think.

DR. SHANKER: I think we want to split things a couple of ways. First, I think we've all sort of on board that we're assuming here some sort of notion of a day ahead schedule and deviations clearing, at least in the energy component, clearing at the spot market on any basis. That seems to be the uniform thread.

The next step is now we have some ancillary services. And you might want to say -- John referred to the capacity or some of the uplift components, some of the fixed costs associated with that -- do you want to clear those day ahead so we sort of deployed some services day ahead to be there for the real time market and those are carried by the load that bid day ahead, or possibly generators, but in the abstract, I can only see doing that for load for day ahead. And then if there's deviation in the real time market that requires supplemental ancillary services, do those get allocated only to people that are off schedule?

Those are alternatives. We see in the Northeast markets actually two alternative approaches to that: PJM actually closes out, with the exception of synchronous, closes out the uplift charges in the day ahead market separately and the full market clears. And then the deviations and the real time market deviations pick up incremental uplift that's associated with that. In New York, the full uplift charges roll through to essentially into the real time load. So you can do it in a couple of different ways.

The common thread, though, is that the energy deviations are all essentially a function of that spot market we talked about. They are essentially cleared at the LMP for both buyers and sellers.

MR. MEYER: Let me say one thing. Maybe I confused you. That doesn't mean that a load has to be exposed to the capacity ancillary service market. It can self-arrange, which means it brings its own. It doesn't pay the cost for those it brings.

PROF. CRAMTON: I think the real issue with respect to penalties -- and first of all, in energy, there are no penalties, because that's simply done by -- that's the advantage of having a financially binding day ahead market is the real time market then is there to appropriately compensate or punish those that have failed to perform or performed exemplarly.

But with respect to reserves, there has to be, with forward reserves where what I'm buying is the ability of somebody to turn on quickly and provide energy, that's the whole product we're interested in. So if they only turn on one in 20 times when called, then I don't want to be paying them just as I pay them if they always turned on when called.

So I think that, depending on what the reserve product is, there are certainly instances where the compensation has to be reduced for nonperformance. Beyond simply just not earning it that instant when there was nonperformance. Because the real cost can be much greater.

MR. MILLER: Let me ask a question that relates to the reserve or ancillary services market, because we're talking about them as possibly being, you know, methods of compensation to get what we -- you know, the money that's not there. So are there situations where in the reserve markets can be legitimately higher than the energy markets? And I don't want to get into mitigation or anything like that because it's too close. But is that something that's defensible?

MR. MEYER: In the capacity? You mean the capacity cost per megawatt hour?

MR. MILLER: Well, depending on how you're compensating suppliers to make sure that they're there under certain circumstances, call it capacity, call it reserves or whatever you want.

MR. MEYER: I mean, we -- I've just monitored the Texas market recently, and some hours are really 15-minute intervals. The capacity is usually an hour, and the energy settlement is 15 minutes, so they're not quite matched. But I've seen prices on both sides. Sometimes it's higher, sometimes it's lower. I'd say on the average, it's probably lower overall.

MR. O'NEAL: I would agree with that. I think that generally your energy market is the most valuable market, and that's primarily where the higher prices are going to be. I guess it would depend on the circumstances. If you're on a day where you're scheduling up to the last megawatts of generation that are available, presumably, some of the capacity markets might be very highly priced in a situation like that.

DR. SHANKER: I think then the abstract notion would be that they would be the same. And we have time step averaging issues and things like that. We also have whether it's simultaneous determination or sequential, which would impact it. But you would hope that you would see them be the same over time, they both would represent the opportunity costs. If you were holding back a unit for reserves or you're actually calling on it spot to perform, it would reflect the energy market.

To some extent, when you get into constrained situations like you run out of reserves, and there's a shortage situation, I could see some deviation. But presumably, even in that situation, you would want to see both where we typically have caps, you would see both go to the cap, and you should for the spot price for that. If you don't simultaneously determine the markets, I think you have the potential for them to deviate. And I think that also potentially plays into some market power issues. So, again, you know, it's design versus market power. One design might complement, make it easier to exert market power. When you do it simultaneously, you'd see the opportunity costs in both markets, and you'd probably -- you still can't defeat market power, but you would make it more visible if something was going on.

PROF. CRAMTON: Certainly in theory the energy price should be above the reserve price, and the reserve price should fall as the quality of the reserve falls. So ten minutes should be a higher price than 30 minutes. And so when we see these anomalies where the prices are doing something different, it's because there's a barrier in the market somehow so it's not simultaneous, the prices aren't simultaneously determined, or the pricing process is simply flawed.

MR. MEAD: Let me ask another question about ancillary services. Does the design of the ancillary service market and the way that prices are established need to be standardized across all RTO markets? I think I heard Professor Cramton saying no. Let me know if I misheard you, and could I hear from others as well?

MR. CANNON: Could we broaden that question a little bit and go back to each of the markets that we expect an RTO to run? Do the rules need to be standardized, or is this something where we should allow and permit regional variation? I'd like to hear about both real time energy, ancillary services, transmission rights and even the day ahead market if that's one that you feel like needs to be administered by an RTO.

PROF. CRAMTON: Well, there is certainly enormous benefit to standardization for the reason that Mark pointed out. We need to have less uncertainty about future prices in order to -- and what the rules are -- in order to make the long-term sales and purchases that are desirable in the electricity market. And so I'm all for standardization, and especially standardization of the core.

And I'm certainly in favor of standardization outside the core if you standardize on the right standard.

(Laughter.)

PROF. CRAMTON: I'm just concerned that I don't know what the right standard is. So I would -- I think that we need some more amount of time and experience on some of the less important markets. And some of the markets like Blackstar, don't have it be a market. Let's have it just be cost-based. We don't have to have a market for everything in order to have an efficient and competitive electricity market. I think that that's just too ambitious. So I would really focus on the core.

And in terms of beyond the energy market, day ahead and real time, the spinning reserves and possibly ten-minute nonspin. But I wouldn't move much beyond that in terms of a standard market design.

MR. O'NEAL: I'll take a crack at that. If you look at the market that gets upheld oftentimes as being one of the best, it is PJM. And the evidence there is that, you know, a day ahead and a real time energy market working together makes sense. And so I would think that from a standards perspective, you would want to come up with or suggest that a standard design for day ahead and real time energy market is important.

I think it also extends to the ancillary service markets. And like John, I mentioned the spinning reserves, nonspinning reserves and some form of regulation as being some standards that utilities relied on in the past to manage the grid, and those ought to be products that an RTO goes out and procures. So I guess from a standard design, I would argue that those things are important. I don't think that means standard requirements. Each market is going to have its own unique characteristics about how much spin they go out and procure or how much regulation they think they need, depending on the mix of resources they have in their market and the way the load reacts in their market.

So I think we can agree on there's some standard designs. I don't think that means we need to impose standard requirements on every control area.

COMMISSIONER BREATHITT: Shelton or Dave, can I just restate what I'm beginning to hear is that instead of just saying ancillary services should be part of the RTO function, what I'm hearing this panel say is, it's time to start breaking down ancillary services and say there are certain ones that should be included in RTO's functions and maybe certain ones that don't have to be included. Am I hearing you say that? I know, Peter, you said that Blackstar could be cost-based. Is there an agreement that -- go ahead, Roy.

DR. SHANKER: Yes. It can be cost-based, but I don't think it --

COMMISSIONER BREATHITT: It has to be?

DR. SHANKER: I'm happy for it to be. I don't care. I'm simply pointing out that I think it is part of the package, and the package is within the purview of the RTO and you look at it collectively. You've got to keep these things aggregated. It's fine for it to be cost-based. You're only going to implement, you know, startup procedures after an outage through the RTO. That's the only person that's going to be able to do it. The plan and the resources for that are going to be RTO-determined. And so it makes sense for him to administer those resources and somehow compensate people. And if you want it to be cost-based, that's fine. But that is an ancillary service market that you want within the scope of the RTO. I don't think it falls outside. There's just different ways you might approach it.

MR. MEYER: I think in general there's a minimum set, as we've been talking about up here, that should be required of the RTO itself to operate. And as more or less we've been talking, as a provider of last resort as opposed to the sole provider. The only sole provision is probably in the imbalance, short-term or real time.

I was going to try to answer the standard design question. To me, the spinning reserve is important to probably standardize across RTOs and the balancing energy at least compatible. And I hate to say it has to be totally standardized, but it has to be compatible. Because I think back to the California experience where we had ten-minute markets in California and 60-minute outside, and they had a little trouble bidding ten markets across the border because the WSCC rules would not allow transmission to be scheduled or interchange to be scheduled on a ten-minute basis. So they had to actually switch back to 60-minute, which probably said California should have made a 60-minute market at the time for everybody when ten minutes, if they needed it for some special people.

But anyway, what I'm saying is, if you're going to have balancing energy and you want it to be transfer, you need to look at what you want to cross those boundaries, and I think that's probably one that's important that you may want to cross a boundary with. And it's got to be scheduling compatible. If it's not, it's not going to cross. It also can't disadvantage I think people on either side.

And then the spinning I think is important because, you know, one of the big things of utilities and interconnections in general is to be able to share essentially spinning reserves, reserves that could be used in emergencies to offset contingencies.

DR. SHANKER: I think we go back to the original statements. You've got to have the real time energy market associated imbalance done correctly. It's got be security-constrained economic dispatch with locational prices. You build everything else off of that. My own preference would be to standardize on something that looks like the Northeast. There's a lot of fight between PJM and New York, but I think in terms of what the Commission is dealing with, they are virtually identical markets, and in terms of the decisions you're looking at. You know, we're going to argue a lot about those elsewhere. But in terms of the types of decisions you're making to standardize, and I think those markets are identical, and it's a good model.

In terms of gross standardization, you've got to ask y ourself, are you happy with three healthy markets that are internally consistent in terms of Northeast, Southeast and the Midwest? If you are, you don't need to standardize. If you say, jeez, I really want to get rid of the seams even when I have scales at that level and I want to effectively allow a trade from Ohio and the Midwest into PJM or Northeast with consistent transmission rights, so I could hedge, you're essentially saying I want no seams. I may have three RTOs, but I want no seams, and then you've answered the question. When you say that we're off to it is a standard design across all three. We've got to get very, very close to consistent pricing and property rights in order to make that meaningful, and you can do that. There's no reason you can't do that. But the first question is, do you want seams or not? And are three RTOs in the east acceptable?

COMMISSIONER MASSEY: Can I ask you a question? How much more bang for our buck do we get with a seamless Eastern interconnection market with no seams versus three markets?

DR. SHANKER: I haven't simulated that.

(Laughter.)

DR. SHANKER: My gut response is that it is a desirable goal and you can set up the format for them to be consistent and eventually seamless, or you could have scheduled interfaces. It may not be quite as consistent. But I would be happy with three internally consistent markets designed the way I was talking about. And I'm not sure that the next step is that difficult if they all look that way. But if they went three different ways, you know, it seems to me to be such a huge improvement over where we're at right now that that would be a nice step to take.

MR. KLEINGINNA: I'd like to answer that as someone who sits on the seam.

(Laughter.)

MR. KLEINGINNA: And it's difficult for me to imagine why you wouldn't want to standardize across RTOs. It makes no sense to me why, if you had an opportunity to set up a market that was seamless, why you would do anything but that. The fact is that whether it's a dollar or it's $400 million, as has been talked about here, if we've got an opportunity here to make the rules to do this, to make it a seamless market, then let's knock the barriers down. Let's just throw them out the window.

And I appreciate that there may be certain reserve requirements that folks have in certain load pockets or certain areas of the country, and that can be dealt with. But as a practical matter, if the two systems or the three potential systems in the Eastern interconnect don't talk to each other, then we've a real problem, because I can tell you that this August 11th, there was a lot of power going from Ohio to PJM. There's no seam there. The power goes. The power goes there. And you have extraordinary different marginal prices there because there's a constrained interface.

So I think that to the extent that we don't have, or we have an opportunity to standardize and we miss that I think regardless of how much it's worth, it's something that we should do.

MR. HADLEY: As a state commission and a group of commissions that all set on seams, very similar, we would just echo those kind of comments. With the transition between retail markets and wholesale markets and between states, between jurisdictions, between affiliates and affiliates and affiliates and affiliates, we get back to the issue of reliability for this whole process. And if we're going to maintain a reliable system, standardization certainly comes up high on the list of requirements.

If we're going to have a system that we have monitoring of, standardization only makes sense so that the monitoring can be effective. If we're going to have a system that's transparent so that all market participants and all individuals wanting to monitor that market, it needs to be transparent, it needs to be standardized. So for those reasons, I would certainly agree with that.

MR. O'NEAL: Commission Massey, we took a crack at trying to answer that question ourselves for the Northeastern markets, and we commissioned a study where we basically tried to break down the barriers between the New York, New England and PJM ISOs and said what are the potential savings? And of course we only looked at one period of time. But we estimated those savings over $400 million, divided amongst all three ISOs. They weren't just attributable to one ISO. It was all the ISOs benefitted when you broke down those barriers, you broke down those seams, and you allow power to flow where it needed to flow on any given day.

MR. MERONEY: I'm just wondering if we can say a little bit more about what is the standard. Maybe you're a good candidate, Roy. I think we all are aware that there's similarities between the three Northeast ISOs. And we've been talking a lot about the importance of standards. We've been talking a little bit about what's in the core. Can we say a little bit more about what makes up the standard?

DR. SHANKER: Sure. What we have is a day ahead market, okay? It's a security-constrained unit commitment. It's built with, and it is the first market administered by the RTO, and it's the market in which financial transmission rights clear. We create financial transmission rights based on simultaneous feasibility of what this transmission system can handle. It creates firm financial hedges that are the equivalent of firm fixed transmission, the financial equivalent of firm transmission. We commit into those.

There's some deviations between the markets, but basically, at the end of the commitment process, we take a look around and we do supplemental security analyses. It's done differently in each of those markets. But that is again an RTO security function. It's taking a look at what you expect to happen versus what the financial or the day ahead market did. It rolls you into the real time markets, deviations of the balancing market essentially is the real time market. Deviations are all settled at the real time prices established by the real time market. The RTO is coordinating that real time market.

We have ancillary services committed in slightly different fashions, but we have all the services and those requirements met in those three markets. Reserves are essentially committed for a day ahead, including spin to meet locational requirements, a stake in all three of the markets, spin and nonspin. Those commitments are met. They're priced differently, but the RTO is providing that service.

We allocate the uplift slightly differently. But essentially, the security costs and the fixed costs of meeting those requirements for both energy and ancillary services are taken into the market. They're borne by load. Trying to think what other elements in terms of the questions you have. And I think both markets in those designs, except at least for the short run, Blackstar, it is certainly cost-based service. In the short run, reactive services are cost-based services and they also both, if New York and PJM and I guess New England, if it adopts the standard market design, will have a residual ancillary market in the form of ICAP.

The details of each of those elements are slightly different. And so I would argue if you want those elements, I think I have my own personal preferences about how I'd do each one in terms of if I was running the market design. But I think for here, you know, we don't want to get to that level of detail. And I think those markets functioning in a coordinated fashion, which is the key in all the designs, all the ancillary services, energy clearing in a coordinated fashion is the key element for the standard design.

I don't know if you want more detail about any element of that, but that seems to me to be --

MR. MERONEY: I was actually trying to get some sense of a level of detail at which you would sort of think talking about the elements constituted standardization and sort of the level at which other folks can agree and disagree, you know, on those elements. So I think any other opinions.

MR. O'NEAL: I might add that I agree with substantially most of what Roy said -- day ahead, real time energy markets, the ancillary service markets, balancing energy obviously is part of the real time market.

One of the questions that was posed to us was should the RTOs play a role in any of that? Should the RTOs have positions in these markets? That hasn't really come up yet, because I think or at least I hope you'll find agreement that the RTOs should not be involved in any of these markets. The RTOs should not be in the position of going out and procuring any sort of capacity or any sort of balancing energy. They ought to rely on the market, these bid-based markets to do that.

So I guess I would add on Roy's point, the independence of the RTO needs to be maintained. As a result, they don't need to be involved in any of these markets in terms of having a position.

MR. CANNON: Does that leave a role for the regulator to have to specify any particular amount going through real time or through sort of longer term forward contracting? We all feel a little burned from the California experience obviously. But if we just leave it to the market, is that enough?

MR. O'NEAL: I would like to say leave it to the market. The controllers do what they think is right for their own control area so you don't need to impose standards on them. Hopefully the price signals are all sorted out. You get what you need both day ahead and then what you need in real time as well.

DR. SHANKER: All the Northeast markets have adequacy requirements and part of the adequacy requirement in PJM and New York -- I'm not sure about New England -- is that if you are an installed capacity resource, you're obligated to participate in the market. Once you've set up that structure, which is another element in this type of a design, then we're talking about day-ahead commitment and real time energy. But you've got the overview of the long-term adequacy.

Now establishing the long-term adequacy is, from my view, the long-term adequacy requirement is like a tax. It's sort of a social decision that regulators make, FERC can make, you know, we can have votes on it, it can be the state regulators, it can be some sort of analytical process, but ultimately things like one-day-in-ten, that's not a magic number. There once upon a time were some analytics behind it but it's basically a social judgment on how reliable we want the system to be.

You set that, then you drive everything else down the path and then we set adequate resources, those adequate resources are mandated into the market, we have bidding processes and everything else rolls down with it.

MR. MEYER: Let me just comment since you brought up the concern with California. I guess ERCOT has a balance schedule requirement which is much different than what we've heard about in the Northeast. Having designed ERCOT, it was designed for a reason; I'm not really saying the Northeast is wrong. The unbalance has some real merits too. In fact, all these market designs have pluses and minuses if you stack them up, but the issue that you were worried about, there is a normal, if you set the incentive right I guess, the price signal right, the scheduling problem goes away.

There was an under-scheduling penalty associated in California that didn't get enforced. In Texas, we have a different one but we still have one and it will be enforced. It basically creates the incentive. You under schedule, you take an exposure risk on the capacity purchased by the ISO or the RTO on a daily basis. If that happens, then the scheduling will work itself out. In fact, I don't think we've had one imposed yet for under scheduling.

MR. MEAD: The notion of an under scheduling penalty to me is at variance with the notion that buyers and sellers in the real time market pay the same price.

MR. MEYER: It's not an under scheduling penalty in the real time market. What happens is, in ERCOT at least, and I think it's probably a better example in this case, in the day ahead market, the reason we have a day ahead schedule, which we don't have a financial bind to, is still a unit commitment process, so the ISO can determine which units have been committed to the marketplace and how many.

He also compares that to the forecast. If he figures it's insufficient, he buys replacement reserve capacity, which is like a daily ICAP market, so to speak, except it has location bases too. When he does that, that prorated cost in dollars per megawatt is charged. He makes a note of that. Those schedules are frozen and compared to real time on load, and anybody that underschedules plays that prorated issue of capacity cost. It has something to do with the real time market whether they delivered. But it's not really a penalty in the fact that we imposed here's a fixed penalty. It's a variable that means that they're exposed to the capacity market that they should have covered to start with but chose not to for some reason.

MR. MILLER: It sounds like what we've got we have pretty much broad agreement that there's a requirement for a day ahead market, a real time market, and that encompasses imbalances and some break out of ancillary services.

Now we've been talking about ICAP in one sense or another, but it strikes me that we've had not very good experience with regard to ICAP. It's been somewhat of a burden for the retail market. I guess what I'd like to do is, Roy, I guess I'll ask you. Can you give me an example where a capacity market has worked as we'd hoped it would?

DR. SHANKER: Probably not. I have my designs and I would suggest that would work. One of the problems we've seen, I mean, when you talk about in PJM, there are some fundamental flaws in the design. The basic issue is that these are long-term adequacy markets. They were never intended to be and never should have been implemented as daily kinds of markets with daily clearing prices and things like that. You're doing this, remember, think tax, think social function, you're doing this to assure long-term adequacy.

It doesn't make sense to have daily penalties and things like that for a market that was designed to assure adequacy over the course of an entire year. People have been pressed principally because of the requirements of retail access to do things with these markets that they shouldn't have ever done to begin with. They've made the time steps too small. They've prorated deficiency charges, they've tried to accommodate something that was never the function of these markets. And so my general response is that it's a good market, it is an important market. And if you go back to the basics about why you're doing it, long-term adequacy and design of product that goes with that, it would work fine.

The problems in PJM I think in terms of retail are a couple. Underlying most of that has been the failure to hedge. Most of these were against fixed shopping credits and retail, so when prices went up, that's not a failure necessarily of the ICAP markets, it's a fact that you can't make money when you have a fixed income and a variable expense if you didn't hedge. So I think that was a fundamental design problem.

And probably if we had had a long-term adequacy structure in the market to begin with, people would have automatically hedged and the problem wouldn't have occurred. So there's a little mismatch between the proper wholesale design and a very particular retail design.

MR. MILLER: Peter, do you generally subscribe to what Roy just said?

PROFESSOR CRAMTON: Yes, it all sounds so reasonable.

(Laughter.)

PROFESSOR CRAMTON: That the ICAP markets have problems. We haven't seen the ideal on these but the ideal is, yes, something where the RTO is assuring adequacy of valuable capacity. So I think it is more the definition, having appropriate definition of the market. But as I said initially, we end up spending so much time worrying about reserves and capacity markets, and we would have to worry about them a lot less if we were very aggressive on demand response because that really is the best protection for both reliability and mitigating market power.

So I just want to emphasize that that should be at the front burner always.

MR. HELMAN: This discussion reminds me a lot of the discussion we had in the Northeast about two-and-a-half years ago. At that point, we really decided that we had a set of core market features that we wanted, and we have them in PJM, New York, and we had ordered them in New England. Then we had a series of differences that we thought were largely benign, slight differences in ancillary service market structures, some aspects of ICAP that we didn't understand and nobody had heard about software problems at that point.

For the past two-and-a-half years, we've been dealing with those benign differences and all kinds of stuff that was dredged up as the systems tried to implement a similar market design.

I was wondering, Roy, I know you have a lot of experience with this. If you could describe some of the problems that we're going to face as we operate at 60,000 feet and impose what we think is a common market design, but in implementation terms turns out to be a huge headache and really take up a lot of our time here at FERC trying to sort out a lot of details.

DR. SHANKER: Without getting into the real particulars of this and becoming too esoteric for everybody, a lot of the problems that you're seeing, software, et cetera, have to do with building on legacy kind of platforms and a lack of modularity. You can't stress enough the importance of being able to change out systems.

We talked about the energy management systems, the real time dispatch, the SCUC models, they had unit commitment models, day ahead unit commitment models is what I should have said. All these models they change, they get updated, they get ahead. We get slight changes in market rules. The core of being able to resolve those differences and to standardize is the ability to have a basic platform that looks like plug and play so you can modify those things and tune them.

We'll never get it exactly right on day one. I'd like to say they'd all get fixed, but we know that won't happen. And the problems, at least from my perspective, that we've seen in the Northeast, come from the fact that the New York platform in particular does not seem to be very flexible that way. A lot of the things are hardwired into the software and it's difficult to change.

In the abstract, they probably have a better market design, the theory is stronger, the practical implications, though, is PJM has done some things that are like plug and play. They've switched out all the major market engines over the last three years seamlessly. No one's even seen it. Most participant's don't even understand they've done it. They've got a whole new energy management system, a whole new day ahead market system, software completely replaced in the last three years. That's a huge plus for design, even if you don't like the particulars in the market, or the market rules, or that software package, the ability to do that is incredibly good.

So not doing that, designing anything that's hardwired in that's integrated in a fashion that doesn't allow that to be done easily is a huge mistake. You're probably going to get better answers to that from the people that actually do the software design than from me, but that is an overwhelmingly positive attribute or discriminating attribute of seeing what's happened in the Northeast experience.

PROFESSOR CRAMTON: I think that with standards, you are going to have to start talking about details or you do arrive at the situation of two years ago, and you really need this ability to coordinate and communicate interoperability. That's going to involve some of the details and I think what we're saying is that there's a lot of subtle things that you could do slightly differently. The important thing is to pick one that works and then do it. Do it across all the RTOs. It doesn't have to specify absolutely everything and every line of code, but it does have to go down to a point where all the RTOs can seamlessly communicate. That's more than we can do here today.

COMMISSIONER BREATHITT: This is a question in which the detail I think really matters. And if you have RTOs in regions where bilateral contracts provide all the needs, should they be required to change to a bid-based market? In other words, should RTOs be required to run an auction for real time energy in every RTO across the country because we've got both ways of securing real time power now, either bilaterally or through an auction or both.

I was wondering if there was any consensus on whether it should be all bid-based or whether the form of securing it bilaterally and bid-based is still in your view okay. Do you have a preference?

PROFESSOR CRAMTON: I think that you have to have bid-based. The bilateral contracts are wonderful and we would expect the vast majority of transactions to be bilateral but the balancing market has to be bid-based and it has to be mandatory if it's going to be compatible. You can't have a bid-based system, like PJM, communicate with a purely bilateral system in a seamless way; it just can't happen. So I'm not advocating.

The regions where they're doing 100 percent bilaterally, then just put a functioning bid-based system on top of it, and you'll probably find well now they do 90 percent bilaterally or 95 percent. That's great, but you have to have the bid-based balancing market in my mind.

MR. MEYER: I would agree with that. You have to have a bid-based balancing system in each RTO. I don't know of any market that would be 100 percent bilateral because somebody's making the imbalance, whether it's a control area or someone else. Nobody can hit it exactly right all the time unless it's dynamically scheduled through metering or something. That's essentially a separate control area.

COMMISSIONER BREATHITT: But weren't you advocating that the ISO or the RTO not get into that function?

MR. MEYER: We don't want him in the marketplace in the forward markets, I don't think.

COMMISSIONER BREATHITT: Can't avoid being?

MR. MEYER: I don't think you can avoid him being in the real time or spot market. I guess we'll have to define what "spot" is. Some people define it seconds or minutes before, hour before; PJM may be a day before, but it's not a year before; he doesn't take a long-term position in the market is I think the point that the panelists have made up here.

MR. O'NEAL: Could I clarify? Is there a difference here between an RTO taking a position by buying or selling and operating a market by letting participants bid into the market?

MR. MEYER: Right. In Texas, for instance, the RTO doesn't take possession of the energy. He's very careful that he's buying it on behalf of everybody else.

DR. SHANKER: I don't think anybody has suggested, I thought we had a uniform NO to the RTO taking an actual position in terms of ownership or financial interest.

MR. O'NEAL: But that's different from the RTO operating.

DR. SHANKER: Facilitating the market. I think everybody's also said you've got to facilitate a real time market for clearing, and if you do it right, you can complement bilateral contracts. In fact, you should; that's a good thing to do.

COMMISSIONER BROWNELL: I have a question because before we close, I want to get back to something that you call talked about and that's demand side management, and that's great. We're glad that there is universal consensus that we absolutely need to incorporate this into a market design. But we don't seem to have gotten there very effectively. I'd love to hear each of the panelists talk about what it is that we need to incorporate to make sure that happens.

And then on Thursday, what I am hoping is that we can talk to the state commissioners about working with them, since this is largely I think a shared responsibility. But feel free to start at either end or in the middle.

MR. MEYER: Let me just say, in ERCOT, we tried our best to put or incorporate all demand basis bidding. Part of the reason it was easier, I think, is because we're all retailers or will be January 1. If you're not retail, you run into some other issues. However, I think it still can be accomplished but maybe on a little different basis.

In our market, a load can bid anything into any capacity market except regulation. We're backing off looking at that again. Regulation is kind of a tough market because it's a two- four-second market, so you've got to be able to move pretty quick and respond to automated signals. We also have incorporated loads into the balancing energy market.

As was pointed out earlier, the key thing here isn't so much the size of the load, it becomes economics.

They have to have some metering mechanism. We usually call them interval demand recorders, so that it matches the settling interval, whether it be hourly, ten minute, 15 minute, five minute, whatever it is, 30 minute, but it doesn't do any good to try to have a load change behavior in real time when you don't know what its load was in real time to respond to how do I pay them.

So you can try some games with profiling but usually those are found to be inaccurate and totally unusable when you're trying to behave that way.

But I think it's very important, I think in other states where you don't have retail, there's several ways to do it. My colleague to the right pointed out you could have the utilities or the retail providers themselves contract with the loads and essentially bid it into the wholesale market for them and work out the arrangements and that's what usually interruptible tariffs do anyway. Whether they bid it for everybody's benefit or just that utility's IO guess gets to be the question.

COMMISSIONER BROWNELL: Yes, it does.

(Laughter.)

MR. O'NEAL: To me, the first principles are you need to have a bid-based energy retail market where all loads can see that price, whether they are exposed to it or not. Retail access, at least they're seeing the signal.

Then they'll be able to participate in that market, especially if there is retail competition for the demand bidding component. That needs to be a part of it.

But I guess then distinguishing between the wholesale and retail loads, allowing one of the challenges I suppose for state regulators would be the whole issue of aggregation and the ability of smaller loads to aggregate in some form where they actually get some buying power and go out and contract with wholesale suppliers and come up with creative products that allow them to be responsive to real time price signals.

DR. SHANKER: I think the market designs we've all talked about are compatible with demand side management. The real issue is the load seeing the price. We just don't have mechanisms in place. There are a few programs. Georgia Power probably has the largest one with real time pricing. You need more things like that. Right now, that's not happening. It's probably really for the most part at the retail level. It is a state jurisdictional issue. In fact, on some days, I'm very pessimistic about retail and I'd rather see it not occur because I think a lot of the things that need to get done almost have to be mandated by the state commissions and may not be market functions. There may not be enough market penetration of demand metering, interim metering and things like that to really get a wholesale market in the demand side functioning quickly, and you may have to impose it.

Certainly for large customers, you don't, and that may be sufficient, but until we get an elasticity of demand, most of the retail programs that I've seen seem to work at odds with this kind of demand elasticity. There are some pilots that I'm familiar with in PJM and New York. One of the issues has been people wanted minimum prices and I think for interruptions, something that would be antithetical on the generation side, and a lot of it has to do that there may not be, the economics may not be there in terms of true transaction costs for some of these people to participate.

So we have to sort of mature the ability of load to respond and I'm not sure that will happen in a market context. If you really want it, it may be we have to sort of push it, but you've got to push it in a fashion that doesn't corrupt the wholesale design. That's a real important principle. I see a lot of details and I don't think this is the right panel for it, but a lot of details of retail that very often are at odds with an efficient wholesale design.

I don't know how you reconcile that. I think if I was doing it, I'd start with the wholesale design, and then figure out the retail program around it. It hasn't always evolved that way obviously, and that could be part of the problem.

PROFESSOR CRAMTON: I'd agree that real time metering is critical. The customers have to see the prices. This is obviously easier for the large customer's ability to bid in the markets on an equal basis, whether you're load or generation is critical. There certainly is some aspects of demand response that will require non-market solutions, but what we've seen so far is actually the destruction of retail competition through consumers not seeing prices, and what they do see and pay are artificially low, so no one, no matter how clever, can step in and offer creative products that enable consumers to be responsive to real time prices.

MR. KLEINGINNA: I'd echo that. In essence, push back to a certain degree. Ormet has developed this ability without an RTO real time market. We don't have one in the midwest. We've developed this ability to do it, to respond to these types of things. I think by opening up this market, we don't do any damage. We may provide some good, so it seems to me that we do need to focus on it.

That being said, we need to see the prices. I recognize that there may be certain classes of customers who would find it uncomfortable or difficult to respond, but having more choices isn't bad, having more choices is good, and if it costs some folks some money to install metering on their homes, and the payback isn't there, well, folks buy furnaces all the time and the payback isn't there either. We make these decisions in other markets all the time. Residentials make these decisions in other markets all the time, so do commercial customers and large industrials do as well.

I think to not set up the opportunity for those customers to participate and take the paternalistic view that, hey, these guys can't withstand interruption the demand curve is completely inelastic, really misses the point. I would point, once again, to the national gas market. Here we sit in October and the price of natural gas is $2.25. Who would have thought that last year at this time. It was $10.00 in January. And what happened?

There's three Bcf a day of industrial load off the system. There was a demand side response and the price came down. Do we have to be very careful with respect to human needs and those kinds of things? There's no question about it.

But in pushing back a bit, I think if we assume that customers don't look at these things and they don't care, I think we're just dead wrong, and I think they will respond to these types of things. And if they don't, then the aggregator who can potentially make money doing it will respond.

PROFESSOR CRAMTON: And not everybody has to respond. We only need a small percentage of people to be responsive in order to solve a lot of these problems.

MR. HADLEY: One of the issues that we continually hear on the discussion on demand side, is price signals and the customers have to see price signals. If you couple that with the statement that was made that economics may not be there, and not in the market context, one of the aspects of the price signals, if it's only seen in competition with other generation, then the price signal is one type of price signal, and it's based purely on its economics of competing at that level.

If we better try to understand how demand side can also be utilized to offset transmission cost or bills or constraints, or also look at how it could be used for capacity issues of lack of capacity instead of building, there are costs there that are not part of the market signal given in itself. So I think that how regulators can respond to that is certainly an interesting detail that needs to be worked out. The concept between wholesale markets and getting those right first. To allow the retails to follow does make an awful lot of sense, and I would agree with that.

I think this again gets back to our general premise, standardizing some ideas, making them transparent, gives us the ability to maybe cross some of these bridges, and to be able to make demand side part of the equation in a growing way, not just stranded because it's not quite competitive in the economic market.

COMMISSIONER BROWNELL: Thank you.

MR. CANNON: As a hungry MC, --

(Laughter.)

MR. CANNON: I'd like to thank the panel. This has been very useful and I'm sure some of the same questions are going to come up this afternoon, so we'll get another shot at it. Thanks again.

(Applause.)

(Whereupon, at 1:05 p.m., the hearing was adjourned for lunch, to reconvene the same day at 2:05 p.m., in the same place.)

A F T E R N O O N   S E S S I O N

(2:05 p.m.)

CHAIRMAN WOOD: We'll go back on the record and turn it back over to Mr. Cannon for the second panel today.

MR. CANNON: Welcome everybody. We're probably going to be talking about a lot of the same issues but I think maybe from some slightly different perspectives here in terms of exactly what kinds of markets RTOs should and should not be operating.

With us this afternoon, we have The Honorable Glenn Arthur, the Vice Chairman of the Connecticut PUC. Welcome.

Ed Cazalet, Chairman of APX.

Steve Naumann, Transmission Services Vice President with Commonwealth Edison.

Richard J. Pierce, Jr., Professor of Law at George Washington University.

Roy Thilly, President & CEO of WPPI.

And Fiona Woolf, Head of the Electricity Group of CMS Cameron McKenna.

Welcome everybody. I was wondering, Dick, if you could kick it off here, with just sort of an overview of some of the issues we'd like to try to explore further this afternoon.

MR. O'NEAL: Thanks, Shelton. We made so much progress this morning that there obviously is going to be some overlap in the topics. But hopefully we can have a seamless transition to the Afternoon Session.

(Laughter.)

MR. O'NEAL: The theme of the Afternoon Session is titled "Optional RTO Markets." You can probably define optional in more than one way. One way you could define optional is whether or not the RTO should run the market. Another way you could define optional is if the RTO is running the market, whether or not the market participants should have the option of participating in the market. Then what kind of market design options should the market participants have.

For example, if the RTO ran a day ahead market, should the market participants have the option of simply scheduling into that market, and not necessarily being a market participant, but the scheduling would require that they bring their ancillary services and their transmission rights with them.

The day ahead market, as we discussed this morning, would have bidding protocols and the question about bidding protocols is whether or not you could have multi-part bids or whether or not you would outlaw multi-part bids in favor of single part bids. If you had multi-part bids, the option of course would be for market participants to only bid a single part.

Another optional design is whether or not the markets are sequential or simultaneous. We had some discussion on that this morning. Of course, the option for the demand side of the market to participate, as we found this morning, is key. But certainly we would appreciate additional takes on these issues.

And last but not least, would the optional market designs allow for the Commission to better mitigate market power and allow for the market participants to be at less risk for not recovering their costs?

Shelton?

MR. CANNON: Thanks, Dick.

Opening statements. We'll start with Ms. Woolf.

MS. WOOLF: The email that went around on Thursday or Friday was that the opening remarks were to be no more than three minutes and conversational in style to allow the panelists to explain what their position was. Well, I have to say that I don't really have any position for two reasons. One is that I'm not speaking on behalf of any client or organizations. The views are entirely my own, but the other reason that, I guess since 1988, when I started on the England and Wales restructuring, I've been doing essentially nothing but implementation of restructurings around the world, probably about 16 countries now.

I have probably implemented most of the design issues that you are to discuss this afternoon both ways or even three ways. I'll try to give you a dispassionate view of what the pros and cons are and the implementability and some of the lessons that we have learned. I'm afraid you'll suffer a little from the syndrome that in theory of course -- the theory and the practice should be the same -- but in practice, the theory and practice seldom are.

I'm available to answer any questions to the best of my ability on the New England/Wales trading arrangements. I gather Mr. Wood is interested in some of those. I'll have preferences in some cases and some scars to show we're trying to put in place a market design that really didn't want to go together.

There are a lot of moving parts in market design. They also of course, as we heard from Roy Shanker this morning, depend upon the platform, the software platform, that you're building. One of the scars that you have, and you'll remember from California, is that when the software functionality turns out to be different to what you expected, you go back and ask the lawyers to write the rules again. That involves fighting again with FERC, and you all want to avoid that.

Thank you.

MR. CANNON: Thank you.

Roy?

MR. THILLY: I'll use my opening just quickly to give you an idea of the context and perspective that I come at the issues from. I manage a small system about 750 to 800 megawatts. We own generation. We have a variety of contracts. We own no transmission. Our generation is remote from our load. We have to operate on multiple transmission systems, and in multiple control areas. Our objective, our driver is low cost power to the member cities that own us.

What our customers, our members, and their customers tell us they want, is a highly reliable service with a price that's stable over the long term. That's what we are charged to come up with, deliverability is the key for us as opposed to economic theory.

In terms of market design, the market that I operate in, we operate in, is opaque and completely bilateral. It's characterized by multiple constraints that move by multiple small control areas that impede trading and impede optimization for everybody but the control area utility. So that situation shouldn't be hard to improve. I think it's a low bar.

(Laughter.)

MR. THILLY: We are a strong supporter of RTOs.

I participated in FERC's first conference in 1993 on the issue. Everybody agreed we needed them, we don't have one yet, and we were the first non-owner member of the Midwest Independent System Operators. Most of my load is in the Eastern part of Wisconsin, in Maine, and to give you an idea of when I say highly constrained, we have access from only two directions; south and west.

From the south, there is no long term firm service available for the foreseeable future. There is daily and monthly, in some months, there is no monthly this winter for instance, there's no monthly in the summer. We're having TLRs today when I called in this morning. There was a TLR-4 going on in Wisconsin, maybe a five by now. From the west there's no firm period; daily, monthly, weekly, or long-term. All of the existing import capability is controlled by the incumbent utilities of which I guess I'm one with rollover rights, and the interfaces have been oversubscribed because the estimates of ATC, when these requests were granted, are higher than the calculations today.

So marketers are essentially out of market except for non-firm energy from time to time. We are trying to build a major new transmission line to the west. Our Commission announced approval of that line. There have been two lawsuits filed so far before the order has been issued.

So we expect it to be somewhat contentious.

The other thing that characterizes our market is that flows have shifted. Predominant flows have always been west to east. They've been east to west this summer. We can't counterflow, we can't get ATC to the west or to the east at this point across the map. I have 50 or 60 megawatts of load in MAPP, Western Wisconsin. I can't get firm into that from almost any direction because I will overload the Omaha constraint, the Twin Cities loop, or the King Eau Claire line.

So when we talk about well, one other factor, then I'll move on. That is that we have a highly concentrated market. Fifty-four percent of the generation in my market is controlled by one entity and over 90 percent by three.

There is no political will in the State for divestiture, particularly after California. And as a matter of fact, we see the concentration ratios rising with new construction. That said, we favor moving to a competitive market.

(Laughter.)

MR. THILLY: But in some ways it's academic. What we really need is construction of infrastructure and we need mitigation because mitigation is going to be our market, I think. I agree with many of the things said this morning.

We favor the LMP, PJM model loosely. We think the RTO can manage the market as long as it doesn't participate. I have a lot of hesitation about that statement if the RTO is a for-profit transco because I think a for-profit transco will be a market participant because transmission does compete in ways against generation. We believe that whatever you do, the market should err on the side of transparency and full information. Sunshine is very important in mitigating the exercise of market power.

Sunshine benefits customers. We do favor adequacy requirements and ICAP, but we're not sure how to do it. We think that's very tricky, particularly to incent a supply of generation that provides some long-term cost stability in terms of fuel diversity.

And then my final point is the same with load. Load demand side has to be incorporated but again I don't think we know enough exactly how to do it. That's easier said than done. It's a tricky proposition.

Thank you.

MR. CANNON: Thanks. Professor Pierce?

PROFESSOR PIERCE: Thank you. I've been working on electricity restructuring in North America and Europe for the last 20 years. I'm not here to represent anyone. I'm just expressing my own views.

My principal reason for being here today is just to applaud you for accelerating the implementation of your RTO initiative and moving toward, as rapidly as you can, a standardized wholesale market design. I think those steps are essential. I also want to encourage you to continue to move in those directions as rapidly as you can, and to assure you that I looked at your legal authority, and you've got plenty of it. Substantive authority, there's a lot you can do with the words of 202(a) and 212(a).

Procedurally, while almost every power you have is conditioned in your holding a hearing, the courts have been extremely flexible in what they are willing to regard as a hearing. So you have tremendous flexibility to adopt efficient decisionmaking procedures as well, and to tailor the mix of decisionmaking procedures you choose to the nature of the task and the urgency of the task.

I have provided a prepared statement that goes through a bit more detail on that, and would happy to provide any supplementation to you or to your general counsel's office if at any point you wanted that.

(Written statement of Professor Richard J. Pierce, Jr. follows:)

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PROFESSOR PIERCE: I also wanted to urge you to go as far as you can in the direction of uniformity, in the direction of a standardized market design. This is a context in which uniformity itself has a great many advantages. It enhances transparency, it provides an opportunity for a firm to participate in all of the markets, each of the markets that are available, without having to obtain a whole lot of specialized knowledge on each.

I can't think of any reason in this context why it would be desirable to have variations from one region to another. I can certainly understand why you initially took the attitude of letting every flower grow back when we didn't know what kind of flowers were likely to pop up. But I think at this point, we've got several years experience that will permit you to be able to distinguish between the prize roses and the ragweed, or in some cases belladonna might be the better metaphor.

(Laughter.)

PROFESSOR PIERCE: I just urge you to go as far in that direction as you can. There are a couple of really important issues where, one, you're short on legal authority, and the other we've got a practical problem. Roy just mentioned both of them. One is the infrastructure adequacy problem. You don't have the power to say, build that transmission line, it's long overdue. I don't have a good solution for that unfortunately.

The other one that Roy just referred to, and I agree completely, is the problem of how to get demand response. All you need to do, of course, is get the price right, get the accurate price transmitted on a timely basis to the consumer, but that requires a lot of changes in political institutions, a lot of political will combined with installation of interval meters that, as you know, are quite expensive these days. So I don't have a real good fix for that one either.

Otherwise, I'm happy to do my best to respond to your questions.

MR. CANNON: Thank you, Professor Pierce.

Vice Chairman Arthur?

MR. ARTHUR: Thank you, Mr. Chairman and Commissioners, Commission Staff and all the other participants for having us here today.

I'm a fill-in so I have no prepared remarks to make, but have been very active in following the RTO discussion, and was a participant in NECPUC in setting up the ISO. I've been there six-and-a-half years and it was a lot of long, hard work that we went through to establish that ISO and get it approved by you all.

I've also been a member of the NARUC electricity committee for five years. This morning was very enlightening but also raised many questions in my mind. I suspect it did in yours also. I heard terms that were going around so fast that I tried to put a tab on each one of them and figure where they fit into this market discussion.

I think we in the Northeast, and I should speak just for myself, are very concerned about market power, and that was discussed this morning, as many of the issues are on the agenda for this afternoon.

We specifically have a load pocket in Connecticut that's giving us problems now and costing us a lot of money. There is a proposal by Northeast Utilities or Connecticut Light & Power to build a transmission line, but it's meeting quite a bit of resistance by the nimby people. But the lower southwestern corner of the State, which is really financial markets as much as anything else, is very short on electric supply, and there's must-run generators down there that if they stop running one day, they'll be in deep trouble because there's no way to get power there.

That brings up a question about transmission. We're talking about transmission but I'm not so sure we oughtn't also to be looking at generation. I would rather see the generation built down in Southwest Connecticut, although they're not going to allow it, I don't think, rather than just transmission.

So I would like both of those to be examined and go out for bid, if you will, and see how we meet those load pocket considerations.

The seams issue, which I became more involved in and knowledgeable of during your 45-day mediation period when we had two or three discussions a week with the lawyer representing us is more than just setting up standard rules in my mind. There are in ISO New England versus New York versus PJM, there are more than rules that have to be established to overcome some of these seams issues that won't be solved I don't think by setting up a good market. And I hope that you all will look at that as you go through.

It's interesting and challenging to listen to the different discussion on this first panel. Some of it went right over my head, and I feel like I've been somebody studying the market for some time. In fact, I'm going to go back and get a good course on markets. You know, we've been struggling with CMS and MSS in New England for some time and actually have changed course int he last year and decided to use the PJM model for standard market design. We look forward to that coming online soon, although we're talking about maybe 18 months, before we get that market design in place to help solve some of these pricing problems, market problems that we're talking about. Thank you very much for being here.

MR. CANNON: Thank you. Steve?

MR. NAUMANN: Thank you very much for selecting me to talk at this workshop. After listening to the session this morning, I kind of took a step back and said, you know, what we all are talking about here is the design of the electricity markets for the United States in the future. I guess I kind of said, wow, this is a very serious matter, as we saw in California. If it's done wrong, there can be very, very serious consequences. I would suggest that if it's done right, it could be very, very helpful to the consumers. It could solve a lot of issues, such as giving price signals for the site generation and dealing with congestion. The topic that we have is optional RTO markets.

I'm glad Dick O'Neill clarified the word "optional", because I would suggest that we question the a priori assumption that the markets being discussed here, day ahead or ICAP, should in fact be optional. And we would suggest they should be a required function of the RTO to make the markets work right.

I would also suggest that that is not a deviation from Order number 2000. Order number 2000 explicitly said that the RTO should run a balancing market and have a market-based congestion management system. We think at this point that should make explicit what was implicit in Order 2000 that these other markets really are required. And I would again suggest that when you're talking balancing, when you're talking congestion management, when you're talking spot energy, you're really talking all the same thing.

You're talking dispatchable energy and the need to be run as a single integrated market. I believe Roy Shanker this morning talked a bit about that. But they're really all the same thing.

Roy again mentioned the advantages of the day ahead market when we discussed that. I think one thing I wasn't sure came out as clear is I believe Commissioner Brownell asked in her last question about load I believe if you look at the requirement to have a day ahead market, it would be substantially advantageous to load. People who are setting up their shifts and things like that need to know a day ahead whether they're going to be using the electricity or not, and it gives them an awful lot more information than not having a day ahead market.

We're also going to talk about a capacity requirement. Coming from a state that has direct access, I've gone through more meetings that I want to know as to whether there should be an explicit capacity requirement or not. For many of the reasons Roy Shanker stated this morning, we believe there needs to be. We believe in the first instance there needs to be to ensure the reliability, unless this Commission is willing to see $5,000 to $7,000 a megawatt prices being passed on to customers and to sit there and, as you did for the Midwest back in '98, saying that's okay, but I also recognize political realities. We also think the ICAP -- and I use that as a shorthand without prejudging -- that it needs to be in that form makes the markets work, deals with some fairness issues on retail switching when you get to retail access. And in fact, until you get a good load response really are needed again for reliability.

I'd like to just quickly close to say we've been talking about RTOs and designs for a number of years now. We believe it's time to settle on a standard market model, which I would suggest is PJM or something very close to it, set a time limit, something on the order of six months, because as we just heard, it's going to take New England maybe 18 months to actually implement the design.

So if you're talking about making decisions in six months, these could still be a year-and-a-half to two years away from operation. And then I would say just do it.

In closing, I'd like to bring up a book I read about 20 years ago. For those who read it, you'll know. It's that old. Because it's about mini-computers. It was called "The Soul of the New Machine", and you had a bunch of engineers tinkering with this new mini-computer to make it perfect. And one thing I still remember from that book, get it out the door. The market design will not be perfect, but if we're going to have competitive markets, we have to get it out the door with a deadline and start doing it. Then we can tinker with it once it's in operation.

Again, thank you very much.

MR. CANNON: Thank you, Steve. Ed?

MR. CAZELET: Ed Cazelet with Automated Power Exchange. Whatever you decide as part of this process, and I think you should make some decisions, perhaps the fastest and most effective way of implementing what you decide is to use the concept of an independent market operator.

An independent market operator is an entity that can provide many of the market functions, running ancillary services markets, transmission markets, that sort of thing, across seams boundaries in a standardized way with common software. It can be a for-profit entity contracting with the RTOs, and you can get an entity such as that up and running far more quickly, far less expensively, less bureaucratic overhead, while you handle all the governance problems, the allocation of transmission and who owns the transmission, setting up for-profit contracts and all that sort of thing. That's just a better way, a simpler way, a more market-focused way of getting that job done.

I'll be happy to talk more about what constitutes independent market operators. This is not my idea. There are FERC publications mentioning this in Order 2000 or thereabouts.

The second point I'd like to make, I note I'm the only person from out West here. I'm not a market participant. But APX as a company is involved in markets all over the world, from the U.K. to Japan to New York, California, Texas and so forth. But out West, particularly when you get down to the desert Southwest, they ain't even heard of LMP out there yet, okay. It's just a different point of view.

If you go across the West, locational marginal pricing is a long way from being an obvious adopted solution.

So I think you've got a wide variety of points of view. Just to -- what might be right now for the Northeast, might be slightly different in the Midwest and vastly different out West. I think you've got some panelists later in the week who will deal with the West. But I think that's an important topic of discussion.

With respect to the specific issues today as to what markets are optional and what should not, certainly there needs to be day ahead markets. If you look at the more Western solution, those markets are provided by market participants, a balanced schedule requirement encourages those markets to be developed independently, to be done by many different organizations on a competitive basis. It keeps the size of the RTO down. Those same functions can be provided by setting up a balanced schedule requirement.

Should the day ahead markets be coordinated with the markets for reserves? There's one point of view that you put all of these markets -- energy, spinning reserves, ancillary services, transmission -- all into one black box and simultaneously solve a given set of bids for the optimal unit of commitment. That's very elegant but I think fragile. You're putting everything into one piece of software at one place, one time. A bug, an operator error, you know, in this design, and we've got a large portion of the country tied up with one particular market structure, whereas if you have something that is simpler, single-part bids, more iterative or more bid-asked like every other commodity market that works in the world gets something that's far more robust, not dependent on one institution, one piece of software, one market design concept, I urge you to think about the fragility as you move to something that is very specific, highly sophisticated.

One of the reasons it takes so long to put these highly sophisticated systems into place is, they are very complex. As you add such things as multi-part bids, simultaneously doing a number of markets, they get very complex. They are beautiful pieces of theory and engineering, but they take a lot of software and a lot of design and a lot of very sophisticated people to keep them operating. And the market has got to be robust and has got to be able to operate under a wide range of conditions. That means I think very simple market structures like you see in every other commodity market in the world, simple bid-asked forward markets.

You do need a real time dispatch. That real time dispatch will involve some kind of optimization and a calculation of an ex post after the fact price. There's no requirement for that to be a single dispatch for the entire Eastern interconnection. They can be regional. If you go out West, they tend to be even down to smaller parts of the region than that. But remember the spot market, the hourly to five-minute markets, the 15-minutes' worth are not supposed to transact much energy, maybe a few percent.

We've got to get the forward markets right, the forward markets starting years ahead, months ahead, days ahead. And so how do you get those markets right so that you have almost no dependency on the spot market, the hourly market for balancing? There's a concept moving to forward markets that we must have an ICAP requirement. That's another very complex system. I think that can be replaced by proper and mandatory market reporting, just like we require corporations to publish debt equity ratios and other financial ratios. Loads, if they're required to published how much are they priorly committed to forward to delivery?

We can make our own judgments as to whether they properly covered themselves in the forward markets. At that point through the normal state and other local regulatory process, encourage them or mandate them to buy sufficient forward, and they will build those robust forward markets that we're now starting to get in California and the West and that are the key part of restructuring that will provide the forward signals we need to get things done.

The same goes for the participation in load. If you have a system where prices are not known until after the fact, which is the result of centrally optimizing things, that's why loads can't participate. You've got to have a price that's going to go to $10,000 or $20,000, and they've got to know what's happening in order to do something about it.

Somebody mentioned the Midwest, and prices went $10,000 a couple of years ago. FERC stood firm, didn't go in and put price caps up, and we got a response out of the market. Everybody's scared of $10,000 prices now. So they protect themselves. As soon as you put those caps on, you get that result. High prices don't hurt anybody unless they expose themselves to those prices by not properly contracting forward. In California that happened not because of a flaw in the wholesale market but because of the regulation of the Power Exchange and the utilities. They couldn't participate properly in the forward market and force them all into the California Power Exchange. The details of how the California power market was designed is a minor impact on what happened. It was always essentially a retail problem and not a wholesale problem.

So I think taking care to look at the regional differences and where they are right now, looking at the possibility that whatever you decide could be provided by private sector entities, not large RTOs that grow into hundreds and hundreds, even perhaps one day thousands of employees, then looking at how you bring the real time market demand side in, exposing them to very high prices when need be, but strongly encouraging them through their agents and others to make long-term contracts that will enable generation to be built, transmission to be built under long-term arrangements.

Thank you.

MR. CANNON: Thank you. Questions to this panel?

CHAIRMAN WOOD: Let me ask one real quick. Our first speaker to respond to some questions that the last speaker raised, based on your experience, Linda and I met with Cal McCarty last week. We didn't get to this question, so I'll ask you as one who was involved in it, what is it that NETA does through NETA with regard to these markets, both the first panel today, and then these -- those again are the real time, present time market, the day ahead market ancillary services and capacity obligation. What does NETA do in the U.K. market itself? And does it actually farm out anything to the industry or to a contracted awardee or whoever? Who does what and what is required and what's not required over there?

MS. WOOLF: The notion of NETA, which stands for New Electricity Trading Arrangements, was to move away from a mandatory pool which was both managing for the national grid company, the RTO to run as a transco, but also it was mandatory for participants to participate in it. There was no bilateral contract allowed.

So it is now fully decentralized but has what they call a balancing mechanism, what you've been calling a balancing market. It was left to the market to provide the day ahead market, the week ahead, and Ed will know all about that, because APX are a player there.

There had been a plan to ask the national grid to run a day ahead market, but they really I think partly because of the effort of just doing the rest of it, they decided to leave that on one side and see if it would happen the way it happened with PJM -- that the market participants turned around and said it would be very convenient if you, PJM, interconnection at LLC would run a market for us, because we'd like to lock in the price of the day ahead.

That hasn't happened. But what the balancing mechanism does is that it is a highly integrated single market mechanism run by the RTO to provide balancing services and ancillary services and congestion management. They don't have the LMP and FTR system that you have in various parts of the United States, particularly in PJM.

The reason it really works, and I can give you some experience later on if you want to ask that question as to what has happened in its first few months of existence, but it works because the national grid is subject to an incentive scheme to minimize the costs essentially to the market participants of carrying out these services. In other words, if you regard all this as an uplift management scheme, it's given a cost target to beat. To the extent it beats it, it gets to keep half the surplus. And if it doesn't, it eats half the cost, and there's a cap and a collar.

But it is highly integrated. Because if you ask if this is all the same entity, whether it was there for congestion management or ancillary services, reliability needs or for balancing, the early experience indicates that actually the prices in the balancing mechanism have been really quite high and volatile. People will do anything to keep out of it. They've even been caught loading their plant in order to follow their contracted load which is considered to be somewhat inefficient and perhaps not at all what the outcome was intended to be.

I think maybe Ed can give his views on what's happening with these voluntary markets. What they had hoped I think to achieve was to provide options for market participants to trade at short notice in day ahead markets. Obviously, if they could find a price there that was cheaper than their own running costs, they could choose not to run to serve their load, which is I think one of the great arguments in favor of a day ahead market. Adds it's also I think an argument for having the ISO run it so it can be coordinated with the congestion management and the reliability and ancillary services, a kind of a last minute. So if you were after the money in one of these IMO-administered markets, you would still have an option to participate at the last minute.

What hasn't happened in the early stages yet is something I agree entirely with Ed is those. There was a huge hope that something that had never happened in the England and Wales pool, that there would be the development of a forward market would happen. And really, there's no evidence of this happening yet. But maybe people are still full of hope, and it will occur. But clearly, the absence of a forward market is difficult, because it's not really a full market with people able to hedge their position.

CHAIRMAN WOOD: By "forward", do you mean -- how far forward are we talking about? Obviously, they're doing something ahead of real time. Otherwise in order to avoid the volatility.

MS. WOOLF: I think they're talking about sort of further ahead than a day ahead. There's obviously physical contracts which will look forward in time. But I think we're also talking about contracts for forward delivery.

CHAIRMAN WOOD: How overbuilt is the generation side of the market down there, or is it overbuilt?

MS. WOOLF: It's very interesting you asked that question, because yesterday I thought I'd better take it from the horse's mouth, and I rang up one of the leading market participants to see what the experience was under NETA and asked about the plant margins. At the moment the prices are relatively low, and there are a lot of decisions to retire uneconomic plant, some of which are not fully announced yet.

So there's a lot of to-ing and fro-ing. And certainly there has been a lot of new generation built. In fact, it was a criticism of the old England and Wales pool that there was too much generation coming on there. That was partly because there was a capacity adder in there, which is relevant to your ICAP discussion, which was easy for -- well, at least it's alleged. Let me be dispassionate. I'm sorry. It was alleged that the larger players could game this particular pool rule by some strategic withholding of plant and drive this up. And once you've got the hang of how to play this game, it was one that brought in more capacity than you needed.

CHAIRMAN WOOD: When Linda and I asked Colin whether there was an overbuild at least prior to retirements that might be announced in the mid-20 percentile range, I just wondered if that has an nexus between that and the fact that people aren't doing much in the forward market for so much right on the ground there to pick up in the spot.

MS. WOOLF: I think it's very difficult with a market as young as that to talk about cause and effect. It only came in in March. Actually, I think it's also in this whole area of ICAP. It's very difficult to talk about cause and effects of whether a plant deficiency was due to the lack of an ICAP obligation.

You could turn around and say we had problems in Alberta. Do we know whether if there had been an ICAP obligation there you wouldn't have had the problems? Similarly with Victoria. There may have been other reasons. Eventually what seems to happen is you get some crisis and everybody wakes up, and then suddenly three years later, plant is there and it's built, and everybody's blaming it on the siting authorities.

CHAIRMAN WOOD: Commissioner Arthur, I had a question. YOu said something about "they". Is there a separate siting authority in Connecticut for either transmission lines or for plants other than the department?

MR. ARTHUR: The department does not have siting authority. There is a state siting council, but it also has to go through the local towns. That's the nimbies. They don't want the big new structures.

CHAIRMAN WOOD: When there are a lot of jobs attached to them, you want to put a little control house at the bottom of every transmission line, then you get the local authorities on board, but it's hard to do those things in a world that prizes efficiency I know.

MR. MEAD: I'd like to pursue the issue of whether the day ahead market, energy market should be required or prohibited. If I heard Steve correctly, it should be required. To me, that suggests that there's some value that an RTO's day ahead market can provide that nobody else can. And when I hear the opposite view that they should be prohibited, I infer that means that there's some great harm that will befall the market if the RTO operates the market, that that would somehow prevent an entrepreneur who could provide a better day ahead market from entering the market. Could the two of you speak to those issues, and then anybody else chime in in terms of the general issue of whether a day ahead energy market should be required or optional or prohibited in RTOs?

MR. NAUMANN: As far as should it be prohibited, that would imply you would go back to the market in the United States that's working the best, PJM, and say your process is working. Stop it. We're going to take a chance that an entrepreneur can come in and make this thing work just as good as you can. I just can't see that as happening.

We have a model that's working, and we're trying to achieve a goal. There are a lot of things that the day ahead market can do to make the market work better. There are some things that associating it with the RTO, only the RTO can do. For example, if you have a system with point-to-point rights such as FTR, such as we have in the Northeast, only the RTO on a day ahead basis can reconfigure those rights. You can't have an entrepreneur out there reconfiguring them to make sure that you have a simultaneous feasible solution. So what you do is, you add some flexibility to the system so people can turn in their FTRs and have them reconfigured for the dispatch that they want.

It provides market participants the ability to lock in energy and congestion prices in advance, avoiding the real time market, which to a large extent I think is something that you want to give people the option to do.

I mentioned earlier, it provides a greater option for loads to make their decisions on a day ahead basis rather than only on a real time basis where one of the things we found in our service territory in setting up our DSM programs which are on the order of 1,200 to 1,400 megawatts of DSM is that the feedback we got from the customers was if you give me an hourly price that's too late. I really can't do very much. My workers are here. My material has been delivered. I've already set up for my manufacturing line. But if you tell me a day ahead, then I can do things.

We've been dancing around the reliability issue. The day ahead market allows the RTO to set up to ensure deliverability of those resources. The last thing that we want to do is to get into the hour of operation and have insufficient resources committed, not because the resources were not built. I absolutely agree that capacity requirement is a longer term issue. Somebody has got to go get some turbines or whatever, get them in the ground, and get them built and financed. But it would be just a terrible situation to have plants that might have a 12-hour or a 24-hour or even a six-hour startup not committed because we didn't have a deliverability screen on the day ahead.

So I think when you come down to could you in theory do it, do the system without a day ahead market, probably. Would you have a much better system with a day ahead market integrated within the RTO? And let me just say one thing. It doesn't mean the RTO as itself needs to run those markets. The RTO can contract with an independent market operator that is closely coordinated and integrated with the transmission operations. It's not saying that, you know, all the shirts have to be the same color.

BUt it is saying that to get the result that I think we all want, you need to specify that these are the characteristics of the standard market model that the RTO is required either to run those or have someone run those markets for them. And we have an example of something that works. Hopefully, that's a long way of saying yes.

MR. CAZALET: Thank you. It's good to be agreeing with Steve on so many things like independent market operators. Yes, you do need forward markets, day ahead included. I think it's important that in a highly thermal system such as you see in the East, very often you can commit units properly a day ahead. But when you get coal units, when you get hydro units that require management of rivers and storage, the commitment process isn't quite so simple. In fact, if you look at the East, it's very constrained. Unit dispatcher commitment, pump storage and other things often aren't part of the price setting mechanism. Their volumes are accounted for. But it's very hard to optimize those looking at a single hour, a single five-minute period or a single day.

So there are many heuristics you put into any centralized dispatch method, which is what these systems are.

That said, whatever system you decide on, yes, it can be implemented by independent market operators who would then be in a position probably to better evolve it over time. As you need to make changes, keep it standardized across several RTOs. So you can have an independent market operator who has the full capability to provide the most advanced LMP simultaneous flowgate FTR reserves system that would make Dick O'Neill and his recent paper proud, all the way to a forward bilateral market, okay, that would hit the West.

And I think you could put together something that works reasonably well and would evolve over time as the ideas and the systems change. It wouldn't be stuck inside a large bureaucracy who would have a tendency to want to develop their own systems, their own software and that sort of thing and to evolve it, which tends to happen anytime you build a new, large entity.

So I don't know if I answered your question, but I think that's my thoughts.

MR. O'NEILL: Can I get a clarification before we go too far? An independent market operator. I have my own definition, but could you supply us with yours?

MR. NAUMANN: The "independent" refers to the governance and the market operator would have to be independent of all market participants.

MR. O'NEILL: All asset owners including transcos, gridcos, generators?

MR. NAUMANN: Yes. Independent.

MR. O'NEILL: They are a separate entity? They don't have assets it the market, they don't have stakes in the market?

MR. NAUMANN: That's correct.

MR. CAZALET: It would be a professional services organization.

MR. NAUMANN: That's why I said, you know, an RTO goes out and contracts for its back offer functions with somebody, and it could just as well contract with someone to do these functions. They probably would be sitting to a large extent next to each other, but as I said, they'd be wearing different baseball caps.

MR. O'NEILL: But the IMO would not be the transco?

MR. NAUMANN: That's correct.

MR. O'NEILL: I just wanted to make sure

everybody had the same working definition.

MR. NAUMANN: I also just want to clarify just for one second, I think I was clear, but the forward markets beyond day ahead, there would be no reason for the RTO to have to run those. I wouldn't necessarily prohibit an RTO from doing so if the market participants thought that was valuable. But that should not be a required function. Clearly where you don't need the direct connection between the dispatch and the energy could be done by any part in the Midwest, which is as Roy said, very bilateral market. There's a very active broker market that has developed for those purposes.

MR. CAZALET: I missed I think the second part of David's question, which would be why wouldn't you want, what would be wrong with having the RTO run all the markets? For instance if the RTO runs a day ahead market in competition with other market providers, if you decide to do that, then I think it's important that the pricing, the cost of providing that service be unbundled from other services so that if they're able to do that cheaper and better than anybody else, that's the way it's done. If somebody else comes along and can provide that same or better service for a lower price, they'd have to compete for it. So it's just a matter of unbundling and say, okay, what costs does the RTO have for providing this day ahead function of ancillary services? If you provide, if you self-provide your ancillary services, you provide balance schedules, that sort of thing, you do your own congestion management, or if you don't depend on it, then you ought not have to pay the cost of those services.

Certainly with some of the more recent changes int he California tariffs and others, FERC has been moving in that direction. I think it's a healthy direction. And now we're seeing some of the extremely high costs of some of those services from various RTOs. It gives you pause as to maybe there's a better way to do some of those things and achieve the same results or better results competitively.

MR. CANNON: That would not go, though, your last remark, to the real time balancing market, correct?

MR. CAZALET: I think it's too much to expect that in the East. I think when you look out West, for instance in the Desert Star West Connect tariff, you have the opportunities for systems to be self-tracking and to participate in that. There's a matter of degree there.

MR. THILLY: Could I speak for a second on the independence issue that you raised? It seems to me that we have to be careful. If it's simply a for-profit transco outsourcing by contract, the market and controlling the contract and the outsource entity is reporting to the transco, I'm not sure you have independence. I think we have to be very careful about how that arrangement is structured.

MR. O'NEILL: I think the way Steve and Ed described it is the RTO would outsource the contracts to the IMO. WOuld the RTO be a transco?

MR. CAZALET: The RTO could be a transco or it might not be. The RTO might have transcos that are part of the RTO, but the independent market operator would not be a participant in the market in any way, neither owning generation, resources, you know, what have you.

MR. O'NEILL: Do you have a problem with that?

MR. THILLY: Yes. I don't have a problem with the MISO model with the transco underneath it and the MISO contracting out or outsourcing or doing the market function. I do have a problem where it is the transco that is the RTO.

MS. WOOLF: Could I ask Dick a question of what he means by the day ahead market? I just wonder if we might be getting ourselves a little confused. Because what I think I understood it to mean was, if you like, the last chance market before the real time market. In other words, you could envisage -- I seem to be tongue-tied. A day ahead market run by an IMO, you could envisage I suppose several of them. But at some point, all these things have to come together with the RTOs physical commitment congestion management.

I think the argument goes that if all the schedules that are fed into the IMO for that process have to be balanced, then you are, if you like, cutting off a choice or a series of choices, both the generators and loads, who may or may not have been in the markets in which they've participated who may want to buy or offer more services at the last minute, not necessarily for ancillary services or congestion management, but pure energy, that they should have the chance to do that to lock in a price it might not necessarily need to be on the day ahead. It could be on the morning. It depends on the software as to how close you can run it.

NETA is a three-and-a-half-hour ahead, day-ahead market. Was that the sort of market you had in mind? I think we might be getting a bit confused otherwise.

In other words, it's kind of a last-minute monopoly market. There can be only one of it, because it has to be coordinated with the physical commitment and the congestion management.

MR. O'NEILL: I think the market that at least my mental image is the one I think we were talking about this morning -- the primary reason the RTO would have to run it is because it performs the reliability function in addition to being a market. In other words, it schedules the resources in such a way that transmission lines are unloaded so that they meet the contingency requirements, and it is virtually impossible for an entity that doesn't have a purview of the entire market to get all that scheduling right.

And as a general matter, the reason that an RTO should be running the market is because there is some externality, as Peter -- who has I guess left -- said this morning: a market failure, which is essentially the same thing because you can't see the whole market.

In some sense, that's the picture I have. And of course we have operating experience here in the U.S., so that that sort of influences my mental picture.

MS. WOOLF: On that definition, it seems to me you answer the question in the way you pose it in the affirmative.

MR. O'NEILL: I think so.

COMMISSIONER MASSEY: Let me ask you a question, Fiona.

I know that you have been dealing with these issues for years in a lot of different countries, and it does seem to me that you have a wisdom, because you've seen these markets in operation. You helped design them. Some of them have worked well, some of them have not.

I would like to have the benefit of your thinking. If you were in my position and you had to vote on this, what would you standardize and how would you do it?

MS. WOOLF: Well, building on the discussion this morning, I would certainly standardize what there was core agreement on, the need for a balancing market run by the RTO, and congestion management and ancillary services. I think that it does not necessarily preclude self-provision.

So in other words, these markets must be run, and indeed will be used, because you cannot guarantee to be in balance -- even though, as a lawyer, I think I learned this the hard way when, back in '88, we as lawyers sat down and said: Well, if I'm a customer and I've contracted for 100 megawatts and I take 98, I should be punished for doing so.

It was a system of penalties, and all the economists and engineers fell down laughing.

So it must be the motherhood and apple pie that the RTO must run these three markets. They're highly integrated. They're all the same energy, and indeed, you saw the problems of separating the markets out in California. It's easy to game between markets. It's a lot easier to game between markets than within markets.

I think that I would also add to that something which the panel has already alluded to, which is the thorny issue of building the infrastructure. As far as generation is concerned we may be jumping into a conversation that the panel will get into in more detail in terms of the ICAP debate.

Not many countries around the world have the sort of developed ICAP markets or obligations that you have here. It's a rather American phenomenon, and I can understand the design issues you're grappling with. Some people have left it purely to market forces, and some people have put in a capacity payment, if you like, and I think the jury is still out as to whether you can leave it solely to market forces.

I think the trouble is, I think you'd like to leave it purely to market forces if you could design a perfect market that had no market power in it. And that would be my preference. But I do think there's some benefit in perhaps asking people to contract forward. That might help the forward market going.

So I liked the staff paper, actually, that somebody sent me. On that, I thought it was well thought through. So I probably, maybe -- I don't know if you could put it in a transitional basis, and when you've got a perfect market you could transition it out.

But more importantly, I think transmission expansion is a key issue. I know you're all concerned about that, and I think I would put that into the standard market design, even down to the process of pulling it all together. Because I think you talk a lot about the troubles of siting authority and the differences between the states in the way they look at that.

But I think that the national grid had a good model. They'll speak for themselves tomorrow, no doubt, and PJM also. They'll have a process which is highly inclusive of stakeholders, landowners and the states with siting authorities themselves.

It's very transparent. It gives you a -- building on the so-called seven-year statement, a statement of maybe five years that shows the opportunities for connection, where it's economic to locate. It sounds mind-blowingly detailed to put it into the standard market design, but it's so important because the panel has already spoken about the key features of this problem.

I would consider putting it in. I've probably gone on for long enough. I'll think of some more things as we go on.

COMMISSIONER MASSEY: Chime in as you think of other things. Thank you.

COMMISSIONER BREATHITT: I have an observation about ICAP and reserve margins, and I could be off the mark. But it seems to me that our markets are still so nascent that the nation's governors and state commissions have such a long history of making sure that there's a reserve for weather-related crises -- and I'm not sure governors have yet decided that reserves for other than weather-related crises are important yet to factor in, such as markets gone awry.

But I don't know. My observation is that I don't know if we are ready yet to leave reserves to the market. My observation is that they need to be part of a standard offering, because I think governors are still so concerned that there be reserves in their area, and I think state commissioners are still very concerned about that, too.

Dick, you have your finger on the button. Do you have an observation for that, or a comment about that?

PROFESSOR PIERCE: I wanted to share my own thinking on it, because it's changed a bit as a result of observation of California and political and regulatory responses to California.

I thought that we could leave reserves to the market, because I was convinced hat the market would produce adequate reserves if we were willing to allow it to operate with its full volatility. I think we now have a negative answer to that question.

It's apparent that we won't allow it to operate with its full volatility because at some point consumers get so upset that politicians and regulators respond with price caps. Once you recognize it is no longer possible for any regulator to say, I won't intervene and impose price caps if the price gets too high, then we no longer can rely on the market alone to provide reliability, and I back into -- regrettably -- the conclusion that we need a regulatory mechanism for that to assure reliability.

I guess I was a little bit trouble when I heard you refer to governors, and the possibility that this might be state-based.

COMMISSIONER BREATHITT: I think it's getting much more regional than that. The governors still have a certified territory in which they look after. I think they are beginning, very much so, to look at regional energy markets, but they also still have the populations in their states to care about.

PROFESSOR PIERCE: I guess I see some troubling things out there in that respect, where I've heard a number of governors and state legislatures recently -- including in my own state of Virginia -- talk about how we need to be autonomous and independent in all of this stuff, and make sure we're not putting plants in our state that will supply another state.

Unfortunately, this abysmally ignorant parochialism has a rich history.

(Laughter.)

PROFESSOR PIERCE: And a promising future.

I think it's important that we keep the regional nature of this beast in mind, and to remember that state boundaries really make no difference at all.

COMMISSIONER BREATHITT: I think a lot of that rhetoric masks what the real concern is, and that's pricing for new supply, pricing for transmission.

One more observation, Mr. Cazalet, and that goes to something that you said about standardizing certain features for RTOs, where parts of the country are pretty far behind other parts of the country. I've been thinking about that, and wondering how the Commission can overcome that.

It may be that we don't let the fact that parts of the country are not as far along in terms of RTOs, but go ahead and move forward with the standards that we can adopt.

And as those areas get ready to form their RTOs, they could adopt those standards if the Commission decides that they need to be the same all over the country.

Does that make sense?

MR. CAZALET: I understand what you're saying. I think there are certain things such as the real-time markets. I don't think it hurts too much to begin to form standards there. And by real-time, I mean within the hour.

But you do need some kind of balancing market, and that sort of thing. But you know, I think the jury ultimately is still out as to whether or not you want to centralize the forward markets day ahead or week ahead. I'm not so sure.

I would say, well, the western markets might be behind in terms of forming RTOs, that sort of thing. The end game here is that the markets do more of the forward markets, and they move closer and closer to delivery. So to me, even the advocates of LMP have suggested that we would love to get to a position so that what all the RTO does is does the real-time market, because the demand side is still able to participate in real time and forward in real time.

And then, we have a system that works purely with energy markets. That's the end game after things get more sophisticated. So I hope we can set our system up so that the rules necessarily can evolve to that; that we don't simply go to a system where we have more and more of the market functions built into the RTO, which is really -- may just expand and expand and expand, and short-circuit the whole idea of building markets.

It's one thing to have a market for energy. But you also need a market for all the services surrounding energy. I think, you know, focusing for now only on the real time -- I mean within the hour -- is the best thing to do. Begin to work on standardizing that and try to go not too much further than that.

Perhaps you want to standardize within the east on something that's more than that. But if you try to do more than that, it's going to be I think difficult across the board.

COMMISSIONER BREATHITT: You don't advocate the day-ahead market at this point being part of the standard offering?

MR. CAZALET: No.

MR. ARTHUR: Can I make a comment, having been an elected official for ten years? My friend sitting beside me here, a professor of law -- just like they find ways around every income tax that comes up, we'll have people out there finding ways to get around all these. And it is a political issue.

If the lights go out in your state, consumers are going to want to know why. And if you don't have the right answers -- and I sort of disagree with this independent operator coming in. How do you make that organization responsible? Do you let them get to the point where they spend so little money that they no longer control it?

And the lights go out -- what do you do? Just throw them out? Who comes in to fix it?

MR. NAUMANN: I'd like to add a little bit on that issue, Commissioner Breathitt, because I think you remember when you set up the meeting in Chicago back in 1998 --

COMMISSIONER BREATHITT: I wasn't here in '98. It was probably more like '96.

MR. NAUMANN: Near the big airport and the big conference center, after the price spikes.

COMMISSIONER BREATHITT: Yes, the midwest price spikes.

MR. NAUMANN: I'd like to come back to that for a minute to try to answer your question.

As I said earlier in my remarks, we've gone back and forth. And when we started retail access, spent a considerable amount of time -- should there be a capacity requirement for all market participants?

We come from the midwest, where there is not an explicit capacity requirement. There are a lot of recommendations, and we came down on the side of the free market and said, the market will provide the capacity.

Then came 1998, where we saw prices in the midwest for several hours -- not prolonged -- in the $5,000 to $7,000 range. And I do know that we did for one hour -- we bought some power, Com Ed bought some power at $5600. It was 110 megawatts, but that was still a pretty good chunk of money we had to shell out.

And what was the first thing that happened a few days later? The Commission got petitions for price caps. I'd like to say, not from Com Ed; we opposed the price caps. But that was the first thing that happened.

As soon as you saw those prices, the Commission looked at the situation, did an investigation, held a hearing, and came down with what I believe was the correct conclusion: not to impose any caps. What did we see in the midwest in the next few years? I can tell you from the Com Ed service territory only because I'm familiar.

In 1999, all of a sudden, we got 850 megawatts of new peak generation developed within a year to maybe at most a year and a half. By 2001, we had 5,000 megawatts, all of merchant generation. By next year, it'll be 2500 megawatts.

These developers were responding, not only to the prices they supplied, but the expectation that they will continue to receive those prices. And I have to go back to what Roy Shanker said: I believe the developers are looking at Lucy holding the football.

And I'm not saying this in any critical manner, that policymakers have done anything wrong. I understand the real political effects of customers facing those prices, and not wanting to face those prices.

At this point, given what I believe is a reality, I'm no longer confident that the developers will have the same kind of response that we have seen in our service territory and throughout the midwest, where they are fairly sure or absolutely sure there will be bid caps. That's the reason that if you do away with the complete free market response, or are not willing for again good reasons to see those kind of prices, that some other mechanism has to be there to ensure that the capacity is there.

Because I think, as Commissioner Arthur said, this thing really is too important. If the lights go out, there are going to be a lot of people -- not only governors, I suspect, not only state commissioners, but lots and lots of customers that are going to be very, very upset. So that's why we believe you have to have an alternative.

Now, when you have a full functioning market with good load response, do you still have to maintain that? Maybe not. But again, we want to get up and running with something that works so we don't endanger the issue of the lights going out because of being able to have low prices and no service. You need both.

MR. THILLY: Can I comment quickly on that? I do agree with Steve.

The following year, after the price spike hearing that I appeared at also, prices spiked in Wisconsin to $6,000 the next year. I don't think I'd want -- I think a reserve requirement that requires load-serving entities to have 15 to 18 percent capacity under contract is a much better market signal to get capacity built over the long term in a very volatile market.

I strongly support an ICAP market. Also I would say, I think the RTO has to run the day-ahead market for the reasons Dick O'Neill mentioned.

The other piece that hasn't been mentioned is long-term firm transmission rights. You have to have a market for long-term firm transmission rights in order to make long-term resource commitments, to make forward commitments. And if that's not there, that really puts us all into the short term, which is highly undesirable.

MR. CAZALET: If I could comment on the role of price spikes again, letting the prices spike will induce the demand response, so that we shouldn't get $5,000-$10,000 prices very often. You'll get enough demand response so that you will get prices perhaps in the hot summer, very high over a sustained period of time, which then will provide the stable planning environment that generators need to plan against.

I think there's a second thing that should perhaps go into your calculus, and that is, how does FERC relate to the state commissions and their retail rates and their incentives for forward procurement? The nightmare in California was not caused by good or bad design on the California power exchange or the California ISO. It was caused in my opinion by the lack of forward contracting, in effect that prohibited forward contracting. And when the price spike came, we failed to put the rates through to the customers.

So that if you put the utility commission in the position where next time, instead of waiting six months to act where they've raised the rates, demand is down, we're back to $20 prices instead of $200-$300-$400-$500 prices with higher retail rates, the state commissioners will have to face up to the hard choice. We've got to do forward contracting. We've got to protect ourselves against these price spikes, and we've got to put in a retail demand response program so that when they do occur, there's enough of the load exposed to it they can drop the demand quickly.

So if you're going to put price caps on, and ICAP markets and extra reserve requirements and so on, it just puts off the hard choices they must make. And we will never get the demand responsive load. We'll never get the forward market that we so sadly need.

Deregulation, liberalization is not about making a more efficient spot market that only ought to handle 2, 3, 4, 5 percent of the market. It's about getting forward markets, getting efficient plants built in the right place at the right time by the right people -- competition, lowering the cost, technology innovation, that sort of thing.

So I think that it's crucial that you let the market work things out in the forward markets and encourage state commissions to make the necessary changes in the retail market to get it functioning both in the spot market and the forward market

MR. O'NEILL: Can I ask a clarifying question?

We talked around this issue this morning a little bit. Is the ability to respond to real-time market prices or day-ahead market prices sufficient to opt out of the ICAP market? That is to say, if you're willing to participate based on being curtailed at a certain price, is that enough to not have an ICAP requirement?

That is to say, when you opt out gradually over time, entities that have the ability to respond to price and who can get off the system, which essentially lowers load and essentially creates a bigger reserve margin without having to generate or do anything -- isn't that a way to gradually get from an ICAP requirement into a demand responsive requirement?

MR. NAUMANN: Let me just hopefully understand your question.

I think at the beginning there is really no opt out, so to speak. You're supplying your ICAP requirement, or maybe even more than your ICAP requirement, by the ability to be interrupted.

MR. O'NEILL: So in a sense it's semantics. You don't have to buy generation capacity.

MR. NAUMANN: You sell megawatts.

MR. O'NEILL: It's the ability to get off essentially that fulfills that requirement.

MR. NAUMANN: And maybe more.

MR. THILLY: You know, I can have under contract -- I've got a reserve requirement or capacity requirement. I can have under contract a curtailable load, but I have the right to curtail. I also have arrangements with paper companies where I can go in and offer them a day-ahead market price to give me five or ten megawatts, whatever, and we have done that.

So I would manage my load to meet the ICAP requirement, but it's very tricky. Is that a planning reserve requirement that is audited in advance, or is that an after-the-fact determination based on my actual peak? If it's an after-the-fact based on my actual peak, then I'm going to implement those load curtailment demand response strategies to meet my ICAP requirements. If it's before the fact, then you have all kinds of audit issues that are very difficult.

MR. CAZALET: That's the thing about all these ICAP markets. They get so complicated and it takes so long to settle them, and then there are disputes. So it takes forever to know what price you paid or what price you got for your contract.

You need simple markets. Simple markets are: I make an offer, you accept it.

COMMISSIONER BREATHITT: I agree with you.

If the Commission does decide that it needs to have some sort of reserve requirement, then I think we need to have one that's uniform and simple. I agree with you.

I'd just like to make the point that I don't like imposing price caps, and the one set for California is set to expire in less than a year.

MR. CAZALET: I would say for reserve requirements that you start by requiring information to be published. If in California FERC and others had really paid attention to the supply deficit -- and this is why it's so complicated, adjusted for the hydro conditions in the northwest and the plants on maintenance and everything else, it's not real simple. This is really complicated stuff to get it right.

And then start paying attention and say: Look, California, you're in deep trouble. The market's going to start to take care of that stuff.

So it's getting the information out, trying to come up with an ICAP market for California with a variation of hydro from the northwest, maintenance planning -- that is a nightmare. I spent many, many years working on that out in the west and trying to model all of that, and I got my Ph.D in the field. I can't figure it out. I'm sure there are smarter people who can't.

And trying to build a market on that is just a pipe dream. We've got to keep it simple. Publish the information to start.

CHAIRMAN WOOD: I should add that one of the things we're talking about that RTOs do, in addition to competitive open access and real-time current reliability and transmission planning, is resource adequacy. In fact, the Commission's going out to Seattle to do the first of a series of regional infrastructure assessment that looked at a ten-year demand forecast and a ten-year supply forecast.

I really take that information from my own experience in Texas. It really is hard to know why it got built so over-fast, but it did. And we have numbers that are akin to where the UK is, and we do not have an ICAP back in my own state.

But we did at the PUC there publish every day what the demand would be for the next five years based on high, low, medium, what might be taken off-line, what new generation was coming on-line for sure, maybe, probably not.

That information went to the market and the market responded. So I just want to say from those of you out there, I'm not necessarily a believer that ICAP or even what we said in the New England Order about future contracts balanced with demand is necessary from the get go. It may be triggered by a failure of the market to respond, in which case I think, as Mr. Arthur pointed out, and Linda, as you say as well, political demands that we do something about that, but we may not just presume that any response is necessary on day one. It may be triggered by failure to meet a certain excess of capacity on a given summer day or whatever the peaking season would be.

Mr. Naumann?

MR. NAUMANN: Mr. Chairman, I'd like to address the information issue because I think in Maine, where one of the Excelon companies is located, and where most of Roy Thilly's load is located, we have experience in that. Each hear, the MAIN Coordination Center does an audit and they benchmark what the reserves going into the summer are. We had a very interesting result this summer.

Almost all the alternative retail electric suppliers in Illinois had negative reserves. That turned out to be okay. Part of it was because, as I said, the generation showed up in response to the price as we saw earlier. But I think people need to think about what the consequence of a generation shortage is and how that is dealt with in real time, where you do not have voluntary load response. There is simply not the ability of distribution companies to flip the switch and curtail the people who are short.

You're dealing with a shortage first off in a control area and then in a larger market. It's not that the people who have honestly chosen a supplier who has not set up adequate reserves will be interrupted. What happens is, if you run out of real time energy, you start going to an e emergency plan. Again, that's not real great. Lots of us, I think almost everyone on the panel, said maybe not exactly for the same reason, we don't like mandated requirements. The markets should work. That's the better way to do it.

But a lot of us are questioning whether it's realistic for people to a) be able to take those kind of prices for extended periods of time than it takes to get the generation on, and b) when you do get a shortage, exactly how's it going to work when people start having to be interrupted.

So you might want to ask the main coordination center for their audit results. That's an example of an organization that's been doing audits for several years. It got a little controversial as to who was going to show the numbers of having not sufficient reserves would.

Steve, what did the Associated State Regulators do? I guess it would be all state with that data. Do they take that back to the load-serving entities and go do you have your 15 percent extra?

MR. NAUMANN: I don't know what the Illinois Commerce Commission did on that particular issue. Again, in Maine, we do not have a requirement. The audit was instituted really for many of the reasons that you have said Sherman would shine a light out there and show everyone who is short and who isn't. And this is the first year since they've done the audit that people have come up not only short but actually with negative reserves.

I'm just saying that based on that observation -- you may not always be able to solve all the problems -- it's a complicated issue. I agree with a lot of what Roy Thilly said.

MR. THILLY: I can tell you what the Wisconsin Commission did. They did investigate and they are now requiring filing confidentially what your resources and expected loads are. However, in the real world, there is some cutting of corners and making capacity purchase and things that make the system look good or system contingent capacity that can be taken away in emergencies that get counted. It makes it very difficult.

The other point is that when we had shortages, actually the real problems showed up on adjacent systems in low voltage situations so that utilities, mine and others, were in the position of having to cut load perhaps because somebody else was short. So that's another reason why I support ample reserve requirements.

COMMISSIONER BROWNELL: Could I just add that I'm thinking that we're talking about this in an either/or kind of situation as we are wont to do. Will the market work. Will the market not work. When I thought pretty much everybody, and certainly this Commission agrees that we don't have a market. They were in this transition so the issue is perhaps -- perhaps the question is not will the market work, but what do we do in the interim while we're creating markets.

What is an ICAP product that will in fact do what it is theoretically intended to do, and that is send the right price signals, which I would argue does not happen at least in some of the models today. Hence, the report that Fiona referred to. I don't know if you are familiar all of you with that.

I think what I'd like us to do is let's just look at what we need to do for the foreseeable future and not worry about this either/or situation because the reality is, for a whole bunch of reasons, not the least of which is political, we cannot afford to leave this to the whims of a market that is at best engaging in adolescent behavior.

MR. ARTHUR: ISO New England, which is an organization, has that same evaluation of the markets right through the year, and each year they publish when the electricity demand will be the greatest and now encourage the generators to alter their schedules, and of course one of the big generators is nuclear power plants.

If one of those goes off line, you've got generally a lot of megawatts to make up. But they've changed those now from being a spring/summer until the off season so that when those big generators go down, and other conventional fuel plants go down, it's not at a time when we expect to have the greatest demand. They're very involved, and if they think we're going to have a lack of capacity, they're out making contracts with New York State or Hydro Quebec or Nova Scotia or New York, and making sure I guess that's hedging, I don't know what that word means, but they load up so they can bring max capacity into the ISO region if they need to.

MS. WOOLF: To follow up on that, there is a possibility which I've been part of the design of, though I don't think I've ever seen it fully implemented yet, so I can't tell you whether it works or it doesn't. Once this statement and transparency is created, given that quite often the problem is more than there is a lack of peaking plant on the system, what's really needed is fast-start plant, which nobody seems to want to build. They only want to build baseload plant. And unless the market is such where a large player volunteers to build it because it hedges, he'll only do it if there's a self-interest. Otherwise, you're left with putting the RTO into a kind of last resort mode.

And for one of the World Bank contracts that I had, the idea was that the RTO would be empowered, having got this information, this statement, he would see it coming long enough, he would basically issue an RFP inviting somebody to build this peaking plant in short order, rather perhaps hoping it would also send other signals out to the market as well to respond. It sounds like of intrusive and not very market-based, but that's a possible answer.

MR. CAZALET: I might add in California, we all were, I suppose, convinced last Spring. We were desperately short of energy capacity in California forever. We went out and signed some $43 billion worth of contracts that are now about three times current market prices. There's a new state agency form to go out and build 15 percent new capacity reserve margin, so leaving it to the market sometimes that can run into problems, but leaving it to the states can also run into problems, I think.

So there's no perfect solution. I really do think that shining a light on it allows many, many people to work on the problem simultaneously, and so if I think that such-and-such a state is going to be desperately short on power a year from now or six months from now, I'll find a way to make money out of that, not as an exchange operator but as a generator, or as a trader.

That's why we have markets, so you get that diversity of view, that diversity of opinion, that diversity of risk, because if you all put all this responsibility only on the FERC to set standards on forward contracting amounts or on a utility on a local rate commission, or that sort of thing, it becomes political. The idea is to get it out in the market where it is apolitical. Many, many people are making their own decisions to acquire forward, and those who decide not to acquire forward and expose themselves to these higher prices will pay a painful price, but they will be a small minority who won't have so much political clout.

So I think going to the market does solve the political problems by having many, many people making different decisions, taking different risks rather than putting it all on a central system.

CHAIRMAN WOOD: All I can say is you and all of you all help us get there. When we go out and do these little road shows around the country, we're going to it based on the best data we can with our fellow Commissioners and state citing authorities and governors. You all take it from there and then we'll never have to get into this morass. So there's the challenge.

PROFESSOR PIERCE: If I could just add one cautionary note there. You can't avoid politics in this business. This Commission can't avoid politics in this business. Quite apart from the fact that you work for a bunch of politicians --

(Laughter.)

PROFESSOR PIERCE: -- we've got these federalism problems out there where a lot of this is up to state regulators. Information alone won't do the job if the state regulatory apparatus isn't up to it.

California is a good example. I remember Paul Jaskow 1999 when he made a wonderful speech, or he began the speech by having somebody flip the lights in the room, and he turned on his flashlight and he said, if you're going to visit California any time in the next couple of years, you better have one of these with you. This was not any secret. The fact that the demand for electricity was going up rapidly in California, and no new plants were being authorized.

In your state, a state I lived in a few years back, siting is a lot easier than it is in say California or Connecticut, so you get the word out there and people respond with their applications, and then some bureaucrats in Austin stamped them approved and everything's fine.

(Laughter.)

PROFESSOR PIERCE: Well, in Connecticut, it's got to go through the first selectmen of each of 18 villages.

(Laughter.)

PROFESSOR PIERCE: And you've got to throw in three or four municipal swimming pools and there's a lot of risk folks, up there, real hurt by California. Until the recent crisis, they just stalled all the applications and they just wouldn't approve them.

Your problem is, and it really is a problem, you don't have control over any of that and you've got to take the 50 states the way they are; you can't do much about their political environment and come up with a system, a market design that will work tolerably well given the pretty wide diversity in the political environments in the states in each of these areas, and reluctantly, that's how I come out with the -- well, you're going to have to come out with the mandated reliability. I didn't want to do that. I don't think there's a choice.

CHAIRMAN WOOD: I understand that. And I wonder if, as the wholesale regulators, we could say, for example, every load serving entity, whether that be in a bundled state where that's a state regulated entity, or an unbundled state retail competition where it's a certified retail provider of some sort, must carry x percent as really I guess I would call it super-ancillary service. You've got to carry responsive reserve but it doesn't have to be responsive until two years from now.

I don't know. I've kind of got this idea from one of my colleagues in a northeastern commission. That in effect will require you, as a load-serving entity, to buy an ancillary service called "capacity reserve" which is part of what we're talking about on this panel here, but in effect it's no different than spending on Blackstar or all the other things you have to buy. And in an overbuilt area like New England, it doesn't cost much because with the excess capacity, it's going for pretty cheap.

Is that a way to do it?

MR. THILLY: Sure. You can make it a condition in the tariff for reliability purposes I would think. In terms of what Commissioner Brownell was asking the need for quick start peaking capacity. You know, building peaking capacity to recover your costs in the energy market is a pretty risky proposition. You need a capacity payment.

Well, a reserve requirement gets you a capacity payment for peaking capacity, and if I'm buying it for my system, I want my reserve capacity to be quick start, low capital cost, high fuel. I'm not going to run it very much. There's a fit to get that market moving as to where we need it to be. And I don't see why you can't do it as a condition or a tariff provision.

Now I would have the caveat that the same percentage is not necessarily going to apply everywhere. If you've got a highly constrained transmission area, you're going to need higher reserves than you are if you have access to a much larger system for backup. If you have a heavily hydro system, it's a different issue because of the availability of those units compared to the availability of others. It's not a one-size-fit-all reliability requirement, but once you determine what the percentage is, you can have a uniform tariff provision.

MR. ARTHUR: Mr. Chairman, along the same line in the Northeast, NEPOOL and ISO New England lost four nuclear power plants in 1995 and we didn't get two of them back, but we sweated through two summers. Fortunately, they were cool, or we would have been in deep trouble. I guess maybe that's the market inspiration, having the people come forward to build.

Right now we have people in New England who want to build everywhere. Sometimes it's not appropriate because where they're building is not going to help the transmission system. But we need some kind of incentive, if you will, I believe, in order to make that happen. I'm not sure what it is.

Having gone through this couple of summers watching the megawatts go up, up and up, and this year we set records, and we maintained the system, and the peaking units are there. Someone said they're not. Some companies are building peaking units and they expect to get their money for 40 hours, 80 hours a year. Maybe that's the capacity factor that we ought to rely on.

COMMISSIONER BREATHITT: Does the panel have any thoughts on whether a capacity obligation should be, as Nora suggested, for a period of time and then expire? Or should that not be answered at this point and see how the market develops, and settle it later on. Do you have any thoughts on whether it should be for a period of time and then expire or perhaps permanent?

MR. NAUMANN: I would think permanent is an awful long time.

(Laughter.)

MR. NAUMANN: I guess again our feeling is that we need to get, as Commissioner Brownell said, a lot of places there are not markets. Absolutely I agree. We're looking at what type of market design do we need to have these efficient markets up and running as soon as reasonably possible.

I would say that as part of that standard market design, you should go in with some sort of capacity requirement, and once the markets are running and they're developed and hopefully you get load response, you always evaluate and reevaluate what is the right thing to do. It may well be that as much as I would like standardization, it may well be that in certain areas, load response, for one reason or another, develops faster than in other areas, and those are factors I believe the Commission should look at when evaluating it.

I come back to the serious issue. No one here wants to say the lights are going to go out because of a mistake that could have been avoided. That's probably not a good choice of words except I've been in the utility business for 27 or so years and you know our first job is to keep the lights on, and that's really ultimately what we're talking about is having sufficient iron on the ground, and I will include megawatts for that, just to keep the lights on.

We need to be flexible in that matter. Again, forever is a long time. Do good evaluations as the markets go into operation and this won't be the only change. I don't know how many changes PJM has made since they went into operation. I guess it's more than the number of fingers I have on my hands. This would be just one more, albeit a very important issue.

MR. CAZALET: I think when it comes to ICAP markets, you've seen great difficulty in implementing them so far. To implement them for only a couple of years, I'm not sure is worth the time. Publish the standards, try and evaluate people how well they're meeting reserve requirements, that sort of thing. I think you'll get most of the bang for the buck. And short term ICAP standards aren't going to be enough for people to build power plants on anyway, so you're only choice is to make them very long-term. And I don't think we know enough to do it right at this point in time.

MR. CANNON: Ed, realizing you disagree, I'd like to come back to just for a second for Roy's point that one size might not fit all. Are you making that statement in the context of let's say there's a single RTO that covers the entire midwest. Would there be one set of rules for t entire RTO or are you talking flexibility from one RTO to the next? Are you talking about flexibility within the RTO?

MR. THILLY: It depends on how big the RTO is I think. You may find pockets in constrained areas where the loss of load probability study is going to tell you you need a higher percentage of reserves than in other areas where there's wide access to a variety of suppliers. I mean, I think we ought to go back to the engineering and why we have reserves in the first place and the studies that determine the percentages.

MR. CANNON: It could change from area to area but it would still be one set of rules that would apply.

MR. THILLY: Absolutely. And the same thing with operating reserves. You need to know where you need to have them. You can't have them all in one section or one piece of the RTO. They need to be -- that's why the RTO's short-term reliability responsibility is so important in managing the ancillary services.

MR. NAUMANN: Of course, the Alliance and MISO are going to be two of those large RTOs.

(Laughter.)

MR. NAUMANN: But I think to the extent that you are operating both operating reserves and long-term capacity, I agree a hundred percent with Roy. You need to go back to the engineering.

The fact is, if you look at the Midwest, the area I'm most familiar with, ECAR, MAIN, and MAPP, we generally have much the same standards, although Roy can correct me. I believe for utilities in MAPP that have a high percentage in hydro, they have a slightly different standard based on the hydro, but other than that, where you have large coal and nuclear plants, and such, we run the LOLE calculations and pretty well come out on a gross basis at approximately the same level.

So I don't think if the RTOs reflect more or less natural boundaries, I don't think you should have any great deviations in the reserve requirements. Clearly, MAIN and ECAR eventually sooner if not later have to end up calculating operating reserves saying we have slightly different ways of getting at the same answer. But we really should end up doing it the same way and getting exactly the same answer.

So to have a deviation within an RTO market, I think there would have to be a very, very, very good reason like I'm a hydro utility and the rest of you are coal utilities, and my characteristics are so different, my engineering characteristics are so different.

The other issue Roy brought up is the location. That of course has to be done, has to be looked at in any case, even if you have uniformity. In the reserve requirement, you may have a location that's a load pocket that for that reason may need somewhat of a different requirement put on it because you simply do not have the ability to use the reserves outside of that load pocket to meet the same standard.

I think you go back to the engineering.

MS. WOOLF: I think if you do that, and I think you're right, you begin to call into question what is actually causing the problem if the problem is being caused by lack of transmission capacity, for example, it's kind of hard to have a single RTO with different rules for different areas because you may be entrenching the maintenance of that constraint where it would be beneficial actually to alleviate it. I think it's not an issue that's easy to answer in black and white terms.

MR. O'NEILL: As I understand it, if we had a single standard for the RTO, like n-1 contingency or something of that nature. Unfortunately for Roy, that may require him to keep a higher reserve margin because of his transmission constrained status than somebody else. The standard would be the same. You have to meet a certain contingency level whether it's n-1 or n-one-and-a-half or n-2 or something like that. But that may translate from an engineering point of view into different requirements.

And if in fact Roy gets the transmission line built that he so dearly needs, n-1 is going to lower the reserve requirement so that there are still incentives to build the infrastructure.

MR. THILLY: That's right. And maybe if customers in Wisconsin and our regulators saw that we had to carry 25 percent reserves, while Steve carries 15, we might find more support for transmission.

COMMISSIONER MASSEY: Could I shift gears just a minute, although it's relevant to what we're talking about, and ask Professor Peterson and also Roy Thilly. Dave Svanda, this morning, the Commissioner from Michigan, suggested that this Commission establish in the Midwest -- that's where he's from -- a regional board under Section 209 of the Federal Power Act to allow state regulators to have a forum to work on just these very issues.

One of the issues that could be discussed in that forum could be a reserve requirement and what it should be over an 18-state area. Do you think that is a practical solution for this Commission in working with the states? After all, on a number of these issues, such as how to facilitate a robust demand response, we simply can't do it on our own. We can pontificate about what a good wholesale market requires and define it.

Let's assume we define it correctly. We can't make it happen. We can't without the states' cooperation, we can't facilitate a good demand response. I'm not sure we can implement any sort of reserve requirement without the cooperation of the states if it's a requirement placed on the load-serving entities. I'm not sure about that, but what do you think about that mechanism? Is it a good idea or is it too cumbersome? It's been in the Federal Power Act forever and it hasn't been used by this Commission in years.

PROF. PIERCE: I worry about it. I think it's very important that this Commission be listening all the time and actively soliciting the views of the state commissions and vice versa, that this Commission be doing everything it can proactively to make sure that the state commissions are aware of what it's doing, that there be very, very good channels of communication there. Going beyond that and establishing any sort of formal regional mechanism concerns me.

I think the politics there can get incredibly complicated, and it's not at all clear to me how such an entity would actually work, even if you were talking about just three or four states, much less the much larger number of states we're talking about in this situation.

If you look at generally how interstate compacts share, there's a lot of squabbles, a lot of transaction costs. I just watch with sometimes amusement and sometimes not so much amusement as a taxpayer of one of the two states, I watch Virginia and Maryland go back and forth and back and forth on water from the Potomac River. They're in court on that all the time. They're not able to work it out between themselves. There has to be an entity that comes in and resolves those kinds of disputes. And I'm afraid you guys are stuck as that entity.

MR. THILLY: What I heard this morning was sort of frustration at the competition between these two RTOs and what Steve just described as a natural market. You know, a lot of questions as to whether seams agreements will work, lack of a stakeholder process in one or not the other or whatever. I think you just need to deal with those issues rather than study them for another long-term joint commission.

Where I do think getting the states together is crucial is on siting. I think the RTO has got to come up with a transmission plan that is a regional least cost transmission plan and then we've got to get it sited. And every single line is going to go across borders and have implications in other states. So if we're not going to go to a federal siting process, we need a joint state siting process that determines need on a regional basis and not on a state-by-state basis, and that, I think if we're going to work to get states together, that's really the primary place where we have to focus.

MS. WOOLF: The question for Professor Pierce is whether FERC has power to move there on its own absent any legislative changes. If I understood when the Enron conference was at its height last week, or was it the week before, there was really no appetite at all to step on the issue and even to question the states' involvement. Therefore, as a complete outsider, how can FERC make this happen on a voluntary basis that the states want it to happen on a voluntary basis?

It makes a lot of sense. The obvious compromise between state and federal is a regional solution, and it would solve a lot of problems. But do you feel it could be made to happen on a voluntary basis?

MR. ARTHUR: In NECPUC we've talked about this too much probably over the last several years and have not come up with what I think is a workable situation. Even in that six you might call it small state area, there are differences about how we do things, especially when you talk about transmission lines or where you put the generation, where you site it and who decides is certainly a big issue.

I guess maybe we're fortunate that a lot of generators have come to the Northeast states and proposed bringing generators in. If we had 18 states to deal with, I'm just not sure who would call the shots. All they would have to do is probably come up with something you all would have to act upon. For instance, one of the issues would be who represents each one of those states and what his political background is and what he's looking for as far as his governor or his legislature and those are not very often exactly the same as what should happen to the whole six-state district.

That's a very difficult issue and I can imagine

18 states trying to figure out where you build transmission or where you try to get somebody to build generation is a very difficult and I guess what I would like to see is FERC more involved in that balancing, whether it's transmission or generation, because our uplift costs that are being socialized currently, there's talk about two to six hundred million dollars a year here in the next three to four years. We could solve it if we had a generator or two in the southwestern part of Connecticut or a new transmission line down there, one or the other.

CHAIRMAN WOOD: Or not socialize the costs I guess if there are ways to directly assign them.

MR. ARTHUR: That's true.

PROF. PIERCE: Let me just add my agreement to Chairman Wood on that but also just express real pessimism on this question of whether it's likely to get better. I'm afraid it's going to get worse. Looking at the present situation, it happens that my sister-in-law is a long-time first selectman of a Connecticut city. The state of Connecticut does not have agreement on this issue, and the only agreement you'll ever get in the state of Connecticut is this not a state decision. They won't even concede that this should be made by Commissioner Arthur and his colleagues or any other state body. This is a decision that must be subject to local control.

There is a veto for everyone down to the smallest unit of local government. And then when you get up on the state level, I see things like the state of Virginia has been very similar to your state of Texas in terms of a pretty easy state in which to site, if you take Northern Virginia out of the equation. You can site things in most parts of Virginia pretty easily.

Now the Virginia legislature is seriously considering enacting a statute that would change Virginia law so it reads the way a lot of other state laws already read, like Massachusetts, that says it's illegal to build anything in the state that would provide one ounce of benefit to somebody in another state, dammit.

(Laughter.)

PROF. PIERCE: Maybe I hope you folks can do some good by doing more educating, more jawboning, not just of state regulators but state legislators and governors on these issues. But I'm not sure that we're even seeing movement in the right direction much less the degree of movement we'd need to get the infrastructure problem resolved.

CHAIRMAN WOOD: I would add for those of you that don't read the local paper in front of the Metro section today it talks a lot about the 21 or so plants that are on the books for Virginia. Fortunately, I think the cat's already out of the bag for my new home state. I hope it stays out of the bag.

MR. NAUMANN: I'd like to add one thing to what Professor Pierce said. I absolutely agree with him. There are whole lot of things that this Commission can do absent additional legislation and even then siting a plant in certain locations with strong opposition is probably not something that's going to happen. But we're talking here about a market design. The Commission can put in a market design that sends the correct price signals to the market participants to build a plant and, I'm sorry, Commissioner Arthur, I don't remember, Southwestern Connecticut or in Illinois north of the city of Chicago, and east of a certain location.

I'm sure you're going to hear a lot tomorrow about the congestion management system. But one of the things we found with these plants that have gotten on line in our service territory is we were not able to provide them price signals. So in spite of the fact that we told, publicly went out and said build plants in the Northeast section of Illinois, that's where we want you to build, that's where the transmission is already there to deliver it, that's where it can serve Wisconsin of the operating plants only two located up there and they're very good and another one is going to come on line next year. But they don't see a locational price signal such that all the plants that have gone in down near Joliet where, yes, there is a lot of gas, and yes, there are transmission lines to hook onto, don't see a locational price that in fact may be very low or at times could even be negative that they would have to pay to run.

I think when you listen to this discussion tomorrow it's important to understand that the market design, at least in my estimation, goes beyond simply the price of energy and the spot market but has an effect on where generators locate and which transmission lines will be built. So I just wanted to add that. That is something this Commission can do in dealing with the nimby and banana folks. That's I guess for us people in the field to deal with.

MR. MURRELL: I've been struggling through a good part of this discussion trying to generalize getting back to the optional RTO market topic for a moment. It seems to me that when you start talking about the forward market, the day ahead market, the balancing market, you're almost de signing a clock. You're chopping the commodity product into different time increments.

I am sitting here wondering now, do we know what the basic foundation unit of that clock in terms of the standardized market design needs to be? Have we identified that, and do we know what optional units we want to provide to make the market more adaptable, more flexible, work better?

MS. WOOLF: While the others are thinking up a better answer than I can give --

(Laughter.)

MS. WOOLF: Back in 1988 this question was answered in two ways. One was by reference the time clock was defined by reference to the scheduling and unit commitment process that the national grid would need to carry out and it's driven somewhat by the ramp-up rates for thermal plant as well and how much notice they needed and how flexible they were because in those days, they weren't very flexible, and it was also driven by certain operational considerations, which is you have to give us time to do this. We have to do this all the day ahead. We have to have everything in by ten o'clock because it's going to take us all the time it takes to get this done.

I have to say that on their behalf I was somewhat intransigent in knowing a little bit about the technicalities of system operations to blind the other lawyers with science, and we agreed that it all had to be done by ten o'clock the day before. And in fact now of course we fall over in amazement that they can do a gate closure for what would be the equivalent of your day ahead market at three-and-a-half hours before. And of course you know the software development that's taken place in the last ten years has been phenomenal.

So I think that in my day you couldn't really do anything within real time. There was only one real time, and it was a whole hour that you could do things within real time.

I think in a sense it's also confusing to the layman to talk about balancing markets and day ahead markets and week ahead markets and all the good stuff that's been talked about as if they are different commodities being traded. And in fact really what you're talking about is the ability to lock in a price. The money and electrons don't have to follow the same path. And now you've all thought up what the answer is, you can give it to him.

MR. CAZALET: I would say what you want to standardize to the extent you need to is the within-the-hour market. Everything else forewarn of that, in some cases it may be a day ahead market, in other cases it's going to be a few hours ahead as it is in the U.K., in other cases the critical things are done weeks and months ahead. And so you need to let that forward market structure evolve to meet the requirements of the local conditions and where you're coming from.

In the East they have a tradition of central dispatch in a pool day ahead. I don't know that you have to change that right away. You don't have that same central dispatch tradition. YOu have a day ahead scheduling requirement in the West but no central dispatch requirement. In the West when we tried to force everything into the California Power Exchange day ahead, we ran into problems. And so just let the prize here is to get good forward markets. And I think by publishing the requirements for reserves and making sure that people are aware of the imbalance and overbuilding or underbuilding of the markets, the markets will develop.

In the U.K. where w e operate a power exchange day ahead, the relatively small volumes are transacted day ahead. There's two power exchanges that compete to provide the day ahead market. Much of the forward market right now is done over the counter. It hasn't formed into exchange. We all expected to centralize and form into exchange as people get used to that, but there is a lot going on in the foreign markets there. They've got I think in their gate closer market 3.5 hours ahead. It isn't perfect. It's got a lot of volatility, but that just encourages more people to get things done well ahead of time.

It would be nice to see that market improved, but it's not essential. Essential is to let the forward markets develop and they're going to be different different places.

I don't think you can standardize.

MS. WOOLF: I think we're in danger of confusion here because the 3.5 hour market ahead is actually the balancing market, and that is essential. And it is essentially the real time market. I think probably we're falling over the difference between a day ahead market and the day ahead market as defined by Dick, which is you know the last chance saloon.

Once you've done all the trading and you may not actually want to be forced to be balanced in one of Ed's excellent day ahead markets, and it might be an eight o'clock in the evening market, shall we say, because that's the latest time that they can take the bids to do then the unit commitment process. In other words, to coordinate with the physical delivery. And there I think the argument against it is it is more efficient and indeed has to be done by the RTO because it has to coordinate with the physical delivery and you do get people saying, well, would you want to give this market, which is essentially a monopoly, to a for-profit commercial entity to run? They could run it as a subcontractor or a contractor, as we've already discussed. But do you want to give to a for-profit commercial entity and create a monopoly, a private monopoly?

I mean, nobody has responded to the contention that RTOs are necessarily, you know, bureaucratic and more expensive from the private sector. Maybe I should put in a word for them. They certainly can be very lean and efficient and you have good ones here. I think the PJM ISO is very focused and efficient. You also have for-profit RTOs for that matter. The national grid is for-profit RTO. It's a transco model.

So let's not debate whether we think for-profit or not-for-profit is good or bad. That's not something you want to discuss this week at all. Let's not get confused about a day ahead market and the day ahead market as defined by Dick.

MR. NAUMANN: I think the RTO has to run the day ahead market for some of the reasons I gave earlier. I think as Fiona said, the dispatch and the commitment and the reliability pieces have to be coordinated by the RTO. I would not go further out than that day ahead.

As far as other forward markets where the people want to contract month ahead or year ahead, those can be run privately like they are now, and I think we also need to remember what I think the goal is. I disagree with Ed that the goal is developing forward markets. Maybe we mean the same thing. I think the goal is developing good, robust, workable markets so that we get correct price signals and people take the right kind of action and that everybody sees those prices.

I also think that you have an example of a workable market in the United States and it becomes a question of how much time now is going to be spent debating the issue as to what this market or markets should look like in the United States. I not only hear, but we believe that we need to get going. We need to get it out the door. It may be a six-month process starting with the PJM model as a starting point, and saying we'll look at modifying that. Because everyone admits that it's not perfect.

Clearly the ICAP issue needs to be revisited as to whether that's the best way of implementing it. But we just need to get down and say the time for experimentation is over. We've had a lot of talk, and we need to do it now, or we can discuss this and be back two years from now discussing the same issue.

The last point I would make is more a practical point, and it's a point for the developing RTOs. They're going to have to implement software systems and other systems for a market design. Order number 2000 requires a balancing market and requires a market-based congestion management system one year from operation. There is a lot of time and effort put into the design of those.

The stakeholder process, duplication in the stakeholder process on these issues, and it seems to me that the Commission has an opportunity here to articulate a standard and say this is what we want, else you're going to get different kind of systems and then having to deal with a conversion from one system to another where people believe they have established property rights under the old system.

It gets pretty hard to change. You have to change the software. Why go through it more than once? Let's try to get it as best we can now or as soon as we can, get it out the door, and let's start seeing the benefits of real markets.

MR. MURRELL: If I could follow up just briefly. If the Commission were to adopt a standardized market design for a day ahead market and let everything else go and be developed more organically either on a regional basis or bilaterally, would that provide sufficient well functioning market mechanisms for the electricity wholesale markets or do you need other elements added to that?

MR. NAUMANN: You mean to say you can design the congestion management, you can design the real time balancing market separately, not on the same standard or you can deal with longer term?

MR. MURRELL: I'm trying to identify what are the mandatory elements this Commission should address first and require in the initial plan and what other things might be allowed to be optional or allowed to be developed on a more nonstandardized basis.

MR. NAUMANN: I think first of all it's a package. I think Roy Shanker this morning said what the elements of a well functioning market are. I think, and I say this with all due respect, and I think I'm quoting Professor Hogan, that when the Commission said in Order Number 2000, put in real time balancing markets on day one and you can wait, it didn't say you must wait, but you can wait until day two to put in a real time market based congestion management system.

There were very good intentions there of getting this done in an incremental manner, but the fact is you can't separate the congestion management system from the balancing market from the hourly energy and all those things. I think you need to put in the standard as a package.

MR. THILLY: I have one concern, and that is in the forward markets everything beyond the day ahead market is bilaterals or whatever. We need to have rules so there's transparency and information available in those markets to everyone and to all the players or we're not going to be able to do the market monitoring that's necessary, and you're not going to have the sunshine that helps prevent market power abuse.

MS. WOOLF: And although it's not on the agenda, w hat goes with that of course is the thorny issue of governance for obvious reasons because you've all been scarred by the problems of it. But also what you're trying to do is essentially a major merger exercise throughout the United States. You get all sorts of people issues standing in the way of sitting down and forming the working groups and the processes that are going to get this thing implemented.

So I would urge you, although it doesn't form naturally a package in standard market design, it certainly goes with it.

MR. CAZELET: If I could comment, even on the words "day ahead market", what do we mean by a market? The term here has come to be us ed as an auction, a simultaneous auction of energy transmission rights and ancillary services. And that's not the only possible day ahead market structure. Markets, and I think there will be great problems putting too much volume into that market, you'll get the same kind of problems we had in California where w e had the California Power Exchange where the price can get volatile if you get too many people depending on it.

So you need markets that trade forward well ahead of the day ahead market, and too much emphasis on the day ahead market I think destroys future forward markets if we try to concentrate too much liquidity in that market.

For example, a day-ahead market that was continuously traded, okay, allowed people -- it's a few days ahead, sell some energy, buy some energy, sell some ancillary services -- creates much more price discovery, allows people to have an idea what the price is before they commit. You have a day-ahead market that is, we'll say, in a part of the East Coast, say the PJM-New England-New York markets and other day-ahead markets.

In the midwest, okay, they're all closing at the same time, and I'm on the border. Which market do I bid into? I've got to commit to one market or the other. So I'm stuck with the seam there.

Whereas if the markets cleared more continuously, as the stock market does, as every other market does, with multiple commodities, then you don't have those seams problems inherent. And so we got to the point now, because we've taken our concepts about optimization that may work for the ex post pricing of imbalances in the real-time market, and tended to take security-constrained unit dispatch and extend it to unit commitment in the day-ahead market. It creates another ex post market that doesn't work well with other markets.

So I think when you say, day-ahead market, you're implicitly including an auction-type market and a single simultaneous clearing, and I don't think that's necessary.

That's not the way the UK's gone, for example.

MR. O'NEILL: Ed, can I ask you a question?

Both New York and PJM have this day-ahead unit commitment market. They keep telling us that very small amounts actually get transacted; that most of the market is bilaterally scheduled and bilaterally contracted.

Are you saying something different is going to happen if we do it somewhere else?

MR. CAZALET: I don't know exactly how much. I know a lot of it is done bilaterally.

But for example, there you have the clear problem that the New York day-ahead market does not coordinate well with the PJM day-ahead market.

MR. O'NEILL: We're solving that problem.

(Laughter.)

MR. CAZALET: Then we still have the problem between the midwest market or markets and the northeast markets, which I assume you'll solve by an even larger dispatch.

MR. O'NEILL: The problem I have is that it seems from your remarks you were saying that the existence of this day-ahead market was going to essentially wipe out the other forward markets. The evidence that we have to date says that these other forward markets flourish, exist --

MR. CAZALET: -- as financial markets.

MR. O'NEILL: Well, I mean, if you're not -- all forward markets are financial markets, because nobody's trading on electricity in those markets. They're just trading contracts.

MR. CAZALET: If we don't get too much volume in them, then that could be fine.

MR. O'NEILL: We'd love a place for APX in all this.

MR. CAZALET: Well, as I say, APX -- in fact, what we find is, in the UK the day-ahead markets themselves don't have large amounts of volumes, just as you said. In fact, we lose money in the UK providing those services. We lost money providing day-ahead markets in California and in the midwest. So we don't find a lot of profit in those markets. We'd probably find a lot more profit if we're able to host a mandatory market or something of the sort.

So no, I'm not speaking for APX when I suggest this. You know, the markets for markets can be very, very competitive, and I think centralizing markets appears to have some advantages in terms of concentrating the liquidity. But it also has some downsides in terms of freezing the market structure, and perhaps getting too much power in various markets.

But if Dick says you won't get too much in the day-ahead market, then I believe him.

MR. ARTHUR: I have to ask a question.

If in fact we go into this commodity market, who's going to determine when we say: Okay, no more computer buying, because it's crashing.

MR. CAZALET: Is that a question for me?

MR. ARTHUR: For anybody who wants to answer it.

MR. CAZALET: I don't know. Pretty much right now we don't have computers in buying and selling. We have people buying and selling, and I don't think anybody's proposing changing this.

MR. ARTHUR: You're talking about a commodity market -- right now, on time, no day-ahead.

MR. CAZALET: There's day-ahead trading. You trade month-ahead, day-ahead, hour-ahead pretty much like the trading's gone on, with better underlying structures, better transmission rights. That's gone on for years and years in the midwest and the west.

There's plenty of over-the-counter electronic trading platforms out there, many many different types.

MR. ARTHUR: So you're agreeing with the number of elements that should be in the market with what was stated this morning.

MR. CAZALET: You mean in terms of --

MR. ARTHUR: Day-ahead, spinning reserves.

MR. CAZALET: I think for now we do need some ancillary services markets, but those will be traded forward as well as up close to delivery. No reason you can't buy your spinning reserve requirements from a producer years ahead if you've got a spinning reserve requirement for your load.

MR. ARTHUR: I think it was advocated that the markets -- and I guess I'm a conservative -- be put on this, sounds like commodity markets to me. My response to that is, electricity is a vital element in our everyday living, and we cannot afford to put it in jeopardy. And some of the things that are proposed I think would jeopardize our national grid system and the availability of electricity for essential needs and also for business.

MS. WOOLF: We haven't discussed multipart bidding, and I was curious as to why it was on the list. Perhaps I can ask Dick to clarify this.

I have implemented both multipart bidding and single-part bidding around the world, and it's sort of yesterday's debate. I don't mean that unkindly, but in a sense there was a view from an economist the other day -- it doesn't really matter one way or another. It's a bit like driving on the right or the left. It doesn't really matter which side you choose as long as you all do it the same way.

There are arguments in favor of multipart bidding: greater transparency, the fundamental point that start-up and no-load costs are different from variable costs. There's a counterargument that it looks terribly regulated, which enables the RTO to check people's costs and maybe intrude with true market forces. And there's another argument that says that actually the software is horrendously complicated and tends to be heuristic, and single-part bidding is simpler. But I just wondered what you were trying to get at.

MR. O'NEILL: I think the reason is because it's still an open debate here in the States as to whether to do that. Again, PJM and New York allow multipart bids, as you were saying -- the start-up, no-load and running costs. And several ISOs -- New England and California -- started out arguing that they didn't need multipart bids; that there was some, like you said, reason that this is not a real market if you allow multipart bids.

Then, very soon thereafter, both found that they needed multipart bids. And I guess just before the real price problem in California, the ISO was trying to implement the multipart bidding system.

So the experience we've had in the United States is that the markets with multipart bids seem to work well. The markets without them in due time seem to need them. And in some cases, at the request of the generators -- because in the single-part markets generators were often getting dispatched in ways that didn't cover their startup costs.

That's the essential reason we put the issue on the table, because I think some people still believe that it's an open question, and that's essentially why it was on this list.

MS. WOOLF: Of course, there is a counter-argument to that that people hate being started up under a three-part bid and then backed down again. But I have to say my own preference is, I think, for -- marginally -- in terms of three-part bidding, notwithstanding the software problems.

MR. O'NEILL: And certainly, anyone who wants to bid single part can in a multipart bidding system.

And talking about entrepreneurs, I got at least three phone calls last week from people, and one visit from people, who argued that they have solved those problems completely and can do unit commitment in four seconds. That may be a little bit of entrepreneurial trade puffing, but there are a lot of folks out there who are working hard on solving this problem.

And I think there are advances in software that are near or on the horizon, and may even get exact solutions instead of heuristic solutions.

CHAIRMAN WOOD: I'm a little intrigued that no one compared anything on this whole day to the gas markets, and I'm wondering: is it an apposite analogy or not?

There is no mandatory RTO in the first place in the gas markets, which may be a plus or minus in some people's minds. There's no mandatory market-making. It is all erected, literally, from the market side of the equation.

You came the closest. I was waiting for you to just hop over the bar there. But you didn't do it. You did, actually, on the first panel, talk a little bit about your experience in the gas markets.

So I'm wondering, you know -- admission against interest, as one who's a big fan of standards, but -- do we need to do any of this?

PROFESSOR PIERCE: I did write one piece seven or eight years ago. It was called, Using the Gas Market as a Guide to Reconstituting the Electricity Market, where I took a crack at that. There's a lot of analogies, but there's also some really critical differences.

One critical difference is, gas transportation is a lot different from electricity transmission. Electricity transmission grids are integrated. People have looked at changing that, and putting the equivalent of valves in every place. The results are not pretty.

CHAIRMAN WOOD: Let's assume -- I guess I'd scope it down to the narrow issues of what we have, a kind of centralized entity required to be set up, like a real-time market for imbalances versus letting a Henry Hub pop up as the commodity trading exchange, that's really basically unregulated by this regulator or any other.

Try to take it down to that level. Because I agree --

PROFESSOR PIERCE: There are two differences that cause the two solutions. One of them is the integrated nature of the grid. Throw in Kirchoff's Law and it's all just this transaction way down here is going to have a big effect on the viability and cost of another transaction a thousand miles away. That's not nearly as true in gas.

The other big difference is storage. You can't store electricity economically. And you combine the two, and my initial crack at the electricity market was in -- what was it, '86, after I'd spent years working on the gas market. And my starting point instinctively was exactly your question. I wanted to use the gas market. Okay, we just apply everything we learned in the gas market, carry it over to electricity.

I started getting into all kinds of problems, and I think those are the two big reasons why. Transmission is different from pipeline transportation; the integrated grid issue. That creates a massive externality problem where every transaction on an integrated grid -- in ERCOT it's a little different -- every transaction, say in PJM, impacts every other transaction in PJM.

And then the other one is the absence of economic storage. If you can solve those two problems, it would be a lot easier to come up with solutions with all of the problems of restructuring our electricity markets.

MR. NAUMANN: Chairman Wood, I'd like to add a third one. You may be able to do something about the first and second with great expense. The fact is that electricity is transmitted at the speed of light -- I guess from cables it's about two-thirds the speed of light.

MS. WOOLF: All this translates -- sorry to interrupt.

MR. NAUMANN: I'm not sure it makes a significant difference, the speed of light or two-thirds. But you don't have line packing to work with, and your balancing -- in fact, you have one of the main functions that control areas were developed to deal with, to balance in real time. And it's on the order of seconds because of the speed of transmission, and the fact that you switch.

I guess probably the best example for those of us who are old enough to remember is when Tiny Tim got married on the Johnny Carson show. And as soon as -- I mean, there were two effects. One had to do with the water pressure in New York, but the other had to do with the system frequency.

And the fact is, right after the wedding was done and they switched to commercials, TVs went off and the system frequency on the eastern interconnect went up. So, something done --

CHAIRMAN WOOD: Not so tiny, is he?

(Laughter.)

MR. NAUMANN: It had quite a big effect.

That's a matter of physics. And while you can have, as Professor Pierce said, you can do something at very, very great expense -- phase-shifting transformers or other solid-state devices to try to control flows, like with valves --

CHAIRMAN WOOD: But take it back to the issue here.

Given that it's an integrated system, there's no storage and the product moves at the speed of light -- minor thoughts --

(Laughter.)

CHAIRMAN WOOD: -- does that tell us anything about the issues of what should be kind of a mandated, required work product from the administrator of at least part of the grid; i.e. the RTO? Is there any analogy?

MR. CAZALET: If I could respond to that, I don't think that means necessarily -- it's a hard problem. That doesn't mean you centralize it. I think there's great danger in putting it all in one piece of computer software or one person's hands somewhere.

In fact, I think the electricity system is so important you have to keep the control of it resilient. Okay, a lot of parallel decisionmaking processes in place, and these wonderful new software systems, okay, that Dick O'Neill mentioned can be used by market participants to achieve economic benefits. So they can figure out a way to move power from one place to another, and you give them sufficient information so that they do that within the physical, security-constrained capability of the system. You don't need to imbed all the market structures, even day-ahead, into an RTO.

You make sure that they scheduled, or they applied, those same advanced technologies. Hundreds of firms, whether it's Enron or Dynegy or a public power entity or whatever, they can go out and do deals and run their own markets -- whatever you want to do. And you get a much more robust, much more resilient system.

We had a serious situation in certain markets in the East Coast when we had the attack. Many of the markets went out of business. We probably couldn't take care of that if we had the entire U.S. market controlled out of one or two data centers.

MS. WOOLF: Essentially, what you're hearing takes us back to what you heard this morning, which is: the essential differences are the need for balancing to maintain system reliability, and to manage congestion. And the costs of congestion are hugely different than they are in the gas model, and very very dynamic indeed, and tend to increase very dramatically after deregulation anyway.

If you look at NETA, and Colin may have told you this, but the whole thing was inspired to make the gas trading and the electricity trading exactly the same, so it was easier for people to arbitrage between gas and electricity -- what they call the sparks margin. So to the extent they could, they took the gas trading model that was already in place, which they rather admired, and put it in for electricity, these long-term contracts.

But the one thing that they needed to add was this integrated, balancing market congestion management, ancillary services reliability core function to make it work.

CHAIRMAN WOOD: I meant to ask you this earlier, Fiona.

The last part of that triage, the last part, the ancillary services that are done under NETA --

MS. WOOLF: Yes. That is all done.

CHAIRMAN WOOD: What are they?

MS. WOOLF: The definition of ancillary services is rather different to yours, but it covers all of yours and then some more. But broadly, everything that's needed to maintain reliability of the system.

CHAIRMAN WOOD: Is it offered as kind of a combined offering?

MS. WOOLF: Right.

CHAIRMAN WOOD: That's only in that three-and-a-half-hour interval. Does someone in the UK -- can they still provide some ancillary services, or is that not something worth doing over there?

MS. WOOLF: Well, in effect they can do that, yes. But whatever it is, the grid needs to balance the system and maintain reliability. At the last minute they will do through offers and bids taken from both demand side and supply side, and of course the key difference here -- which will shock you all -- is that it trades as a principal. It is not independent in your terms of the market.

But then, of course, the incentives scheme I think probably works to make that acceptable, the scheme that incentivizes them to minimize the cost of balancing.

MR. MURRELL: Who trades as a principal? I don't think I understand.

MS. WOOLF: I didn't think you would, because it's counterintuitive to good common sense in deregulated markets. But the RTO trades as a principal and actually buys and sells energy, and indeed can go out in the longer-term markets to do that, and may even be a participant in APX's market for all I know.

MR. MURRELL: So they're almost like a market maker in an exchange where they're buying and selling to keep the market liquid?

MS. WOOLF: Yes, that's right. But they're regulated tightly to make sure they minimize that cost to the end consumer.

CHAIRMAN WOOD: And this is part of this incentive scheme that you discussed already, that says if you minimize congestion and all these things --

MS. WOOLF: -- and ancillary services and balancing. Basically it's to minimize the uplift.

MR. O'NEILL: Fiona, let me understand.

That means the transco or the RTO is the counter-party for every one of these balancing transactions: that is, you sell to the transco and you buy from the transco. Two parties can't get together and do an exchange.

MS. WOOLF: No, it is the counter-party. So it receives all the offers and bids, selects them and decides to buy or sell.

CHAIRMAN WOOD: So do we want something like that here or not?

MS. WOOLF: Don't ask me. I can't answer that question.

CHAIRMAN WOOD: The audience actually answered that question, all right.

(Laughter.)

CHAIRMAN WOOD: The point of this week is to explore all views, folks.

(Laughter.)

CHAIRMAN WOOD: It's a big, big tent here, all right. It gets small real fast, but it's big for now.

Thank you for that enlightenment. It's 5:00 o'clock.

COMMISSIONER BREATHITT: I know.

Along the lines of the point is to get all views, I don't want anybody to think I've made my mind up. I know that you listened to every word we say and think it's where we're headed, but I haven't made my mind up on any of this.

And on that point, on the issuance of October 5, we say: Although the Commission will specifically solicit public input in the rulemaking process, those who wish to comment now may file written comments in this docket at any time before or within the 15 days. So if you have great things to say, other than what the panelists have said, let us know.

MR. CANNON: Even if you agree with the

panelists.

That said, any more questions?

(No response.)

CHAIRMAN WOOD: The meeting is adjourned. We'll start at 10:00 o'clock tomorrow.

MR. CANNON: Thanks, everyone.

(Whereupon, at 5:00 p.m., the hearing in the above-entitled matter was recessed, to reconvene at 10:00 a.m., Tuesday, October 16, 2001.)